

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

HEIDI J. MYERS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

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

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

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

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

7 **Q. Please describe your educational background.**

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

12 **Q. Please describe your professional experience.**

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

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

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

11 **Q. Have you previously filed testimony with the Commission?**

12 A. Yes.

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

14 A. I sponsored testimony in the following cases:

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

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

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

18 Case No. U-17473 – Consumers Energy securitization;

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

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

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

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

23 Case No. U-20165 – Consumers Energy Integrated Resource Plan ("IRP");

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Case No. U-20286 – Consumers Energy electric credit B;
Case No. U-20287 – Consumers Energy gas credit B;
Case No. U-20309 – Consumers Energy calculation C;
Case No. U-20697 – Consumers Energy electric rate case;
Case No. U-20889 – Consumers Energy securitization;
Case No. U-21389 – Consumers Energy electric rate case;
Case No. U-21490 – Consumers Energy gas rate case;
Case No. U-21585 – Consumers Energy electric rate case;
Case No. U-21806 – Consumers Energy gas rate case;
Case No. U-21911 – Consumers Energy incentive/disincentive; and
Case No. U-21918 – Consumers Energy distribution Investment Recovery
Mechanism (“IRM”) reconciliation.

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 electric general rate case. My testimony introduces many of the key proposals included in this case and discusses how these proposals support the Company’s long-range plans to provide safe, reliable, equitable, affordable, and clean energy for its customers. In addition, I give a brief introduction to the Company’s witnesses and the topics supported in their respective testimony and I discuss the requirements for the Company’s next electric rate case (*i.e.*, this case) as set forth in the Commission’s March 21, 2025 Order in Case No. U-21585 (“U-21585 Order”). Finally, I support the Company’s proposed Distribution IRM and ratemaking issues related to the Company’s river hydro assets.

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A. Yes. I am sponsoring the following exhibit:

Exhibit A-163 (HJM-1) Distribution Investment Recovery Mechanism –
Annual Revenue Requirement

A. Yes.

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

Q. Please briefly describe Consumers Energy's most recent Commission-approved electric general rate relief.

A. On March 21, 2025, the Commission issued an order in Case No. U-21585 that resulted in a \$154 million annual increase in the Company's electric rates and collection of a \$22 million surcharge over 12 months for deferred costs related to distribution investments made in 2023. The net revenue increase from the order was 3.8% overall and 4.5% for the residential customer class, effective April 4, 2025.

CASE OVERVIEW

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

A. The Company requests jurisdictional rate relief in the amount of \$436 million and collection of \$24 million associated with the deferred costs related to distribution investments made during the 12 months ended February 28, 2025 (“Distribution Deferral”), which is summarized in Table 1:

Table 1

	<i>(In Millions)</i>
Investment	\$172
Investment – Distribution IRM	\$22
Operations and Maintenance Expenses	\$158
Cost of Capital	\$77
Sales/Revenues	\$7
Jurisdictional Rate Relief Before Surcharge	\$436
Distribution Deferral Surcharge	\$24
Total Jurisdictional Rate Relief	\$460

Q. Why has the Company initiated this rate case proceeding?

A. Consumers Energy’s commitment to world-class performance delivering hometown service means providing safe, reliable, affordable, and increasingly clean energy to our 1.9 million customers each hour of every day. To deliver on this commitment, the Company has developed compelling testimony in this case, driven by the multi-year investment plan identified in the Company’s Reliability Roadmap (historically known as the Electric Distribution Infrastructure Investment Plan or “EDIIP”), to make specific

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1 investments that address asset deterioration and maintain asset health, while also hardening
2 assets against increasingly severe weather. The Company has also devoted considerable
3 effort to developing long-range plans addressing how to transform energy supply to cleaner
4 resources through the Clean Energy Plan put forth in the Company's IRP. Components of
5 the IRP are incorporated into the Company's distribution strategy and vision within the
6 Reliability Roadmap. Together these plans articulate the Company's goals for the future
7 and provide a roadmap for the investments needed to bring this future to fruition.

8 **Q. How has the Company's Reliability Roadmap influenced this filing?**

9 A. As further explained by Company witness Michael P. Kelly, the Company has filed an
10 amended Reliability Roadmap with this case. Starting with the third iteration of the EDIIP,
11 filed on September 27, 2023 in Case No. U-20147, minor revisions were made to reflect
12 the Company's current distribution goals and objectives and the investment plans to meet
13 those objectives and goals. The revisions are primarily centered around updating
14 information to reflect another year of actual historical reliability data, and to extend
15 projected investments by another year into the future. Some content has also been revised
16 to reflect issues highlighted by intervenors in the prior rate case or other regulatory
17 proceedings, specifically the Company's third-party distribution system audit conducted in
18 Case No. U-21305. This Reliability Roadmap maintains planning that includes tools and
19 methods of analysis to better anticipate future challenges. These tools and methods were
20 first introduced in the third iteration of the EDIIP used as the starting point for the
21 Reliability Roadmap filed in this case. This approach underpins the distribution investment
22 request in this case supporting continued investments in infrastructure and spending on line
23 clearing and inspections, while also focusing on resiliency investments. Proposed

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1 distribution spending is designed to meet the collective goal to deliver on the key objectives
2 of the Reliability Roadmap – delivery of safe, reliable and resilient, clean and equitable,
3 and competitive energy to Consumers Energy’s customers.

4 **Q. How do the Company’s proposals in this case support the Company’s Reliability**
5 **Roadmap and its commitment to improving reliability and resiliency?**

6 A. Consumers Energy has plans necessary for transforming the electric distribution system by
7 investing in core infrastructure assets and modernizing the electric grid to deliver safe,
8 reliable, and affordable electricity to customers. Proposals in this electric rate case support
9 the four key objectives used in building the Reliability Roadmap. Company witnesses
10 Michael P. Kelly, Jennifer M. Partlan, Megan L. Hayward, Scott A. McPhail, Daniel A.
11 Schmoekel, Sara E. Stewart, and Andrew R. Snider provide support for the Distribution
12 investments and Distribution operating and maintenance (“O&M”) programs. The
13 Company’s proposed electric distribution spending includes capital investments planned
14 for the test year, the 12 months ending April 2027, that total more than \$1.5 billion, as well
15 as \$301 million for O&M programs. These amounts are comprised of several important
16 programs detailed in this case. The Company has proposed significant O&M funding,
17 more than \$186 million, to support the continued increase in the Company’s line clearing
18 activities to reduce the frequency of outages and move to a five-year line clearing cycle, as
19 supported by Company witness Stewart. Where outages cannot be completely avoided
20 through capital investment, line clearing, or other O&M, the Company continues to
21 implement measures to decrease the frequency and shorten the duration of outages.
22 Company witness Snider supports the Company’s service restoration base O&M funding
23 of \$165.2 million based on the historical year cost adjusted for inflation.

1 **Q. What reliability improvements does the Company expect to see from the investments**
2 **outlined in the Reliability Roadmap as proposed?**

3 A. Reliability improvements provide significant benefits to customers, local communities, and
4 the Michigan economy. The Company's proposed investments in distribution system
5 infrastructure are based on the goal of providing safe and reliable electricity for customers
6 while improving the Company's performance relevant to three reliability metrics —
7 System Average Interruption Frequency Index, Customer Average Interruption Duration
8 Index, and System Average Interruption Duration Index ("SAIDI"). Company witness
9 Kelly presents the Company's modeling projections demonstrating how planned
10 investments are expected to improve reliability across these metrics as identified in the
11 Reliability Roadmap. Based on the modeling results, the Company projects that customers
12 will experience fewer outages on average, and when outages do occur, they will be for
13 shorter periods of time. Projected reliability improvements are based on the Company's
14 planned spending on line clearing, capital investments, and service restoration
15 improvements outlined in the Reliability Roadmap. As explained by Company witness
16 Kelly, these reliability improvements cannot be achieved based on increased line clearing
17 alone. The reliability improvements presented in this case are dependent on necessary and
18 continued investments in the distribution system. Benefits of shifting to a five-year
19 clearing cycle will take time to fully materialize and a line clearing only approach would
20 delay reliability improvements. Capital investments in the distribution system have already
21 begun to deliver reliability benefits and will continue to provide these benefits as the
22 clearing cycle is ramped up. Capital investments in the distribution system should work in

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1 conjunction with increases in forestry work and are necessary to achieve reliability
2 improvements.

3 **Q. Do customers benefit from proactive reliability initiatives?**

4 A. Yes. Vital proactive measures, including tree trimming and vegetation management, can
5 significantly reduce outages and lessen damages from severe weather events. Trees are the
6 greatest cause of interruptions of electric service for customers; mitigating these
7 interruption threats will prevent against interrupted service for customers. As explained in
8 greater detail in the testimony of Company witness Stewart, the Company is proposing a
9 ramp-up to achieving a five-year clearing cycle on the Low Voltage Distribution (“LVD”)
10 system. In conjunction with the increase in line clearing, the Company will continue to
11 invest in the distribution system to ensure reliability improvements expected by customers
12 are realized and not delayed.

13 **Q. Please describe the efforts of the Company to minimize customer costs for reliability**
14 **improvements.**

15 A. The Company has made a proposal in this case that will mitigate the customer impact of
16 the cost of ramping up the line clearing cycle to five years. Company witnesses Patrick D.
17 Daly and Marc R. Bleckman provide testimony explaining the Company’s proposed
18 treatment of the expense related to the forestry ramp up. The ramp up of line clearing will
19 occur over a five-year period reaching a steady-state by 2031. The Company is proposing
20 to defer expense to a regulatory asset for amounts above the baseline line clearing expense
21 and securitize the regulatory asset once the balance reaches an appropriate level. Approval
22 of this proposal would allow for a \$21.4 million reduction to the filed revenue deficiency

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1 and provide customers the benefit of spreading the recovery of this expense over a longer
2 period at the lower cost of borrowing provided by securitization.

3 In addition, the Company has and will continue to work diligently to identify
4 opportunities available under the Investment Infrastructure and Jobs Act of 2021 (“IIJA”).
5 Thus far, the Company has been selected for four grants – a \$100 million grant for Grid
6 Resilience associated with sectionalization and circuit improvement work in disadvantaged
7 communities; a \$500,000 grant to perform pole top rehabilitation and other High Voltage
8 Distribution (“HVD”) upgrades; a \$4.05 million portion of a Grid Resilience grant to
9 prevent outages and enhance the resilience of the electric grid; and a \$19.9 million grant
10 for Grid Resilience and Innovative Partnerships. The final terms of the grants are in the
11 process of being negotiated with the U.S Department of Energy (“DOE”). Company
12 witness Kelly provides more detail on the IIJA grants for which the Company has been
13 selected thus far, associated investments, and efforts taken by the Company to secure IIJA
14 funding for electric distribution investments.

15 **Q. Has the Company proposed measures to further its commitment to the reliability and**
16 **resiliency of the distribution system?**

17 A. Yes. The Company is making proposals in this case that demonstrate its commitment to
18 the reliability and resiliency of the distribution system. The Company is proposing a
19 shortened line clearing cycle, the scaling of undergrounding, the addition of two
20 programs in the IRM, and a Service Restoration Resiliency Fund and Extraordinary Storm
21 Accounting.

Line Clearing

The Testimony of Company witness Sara E. Stewart provides the Company's vision for the line clearing program. The Company strives for fewer tree-caused outages on its system, improving electric reliability for its customers in all conditions. To achieve this, the Company proposes to maintain a four-year clearing cycle for the HVD system and proposes to ramp-up to a five-year clearing cycle for the LVD system as compared to the Company's previous goal of a seven-year cycle. The ramp up to a five-year cycle will occur through 2031 after which a steady-state cycle maintenance will begin to maintain the five-year cycle. The Company has considered feedback received in the third-party distribution audit report filed by Liberty Consulting Group ("Liberty") on November 15, 2024 in Case No. U-21305 that recommended a four-year clearing for LVD. The Company also has carefully evaluated the costs and benefits of a shorter line clearing cycle and determined that a five-year cycle is the right approach to significantly improve electric reliability. As a result of the additional line clearing work the Company anticipates a 30% reduction in tree caused outage incidents by 2030.

Undergrounding

One key element of increasing system resiliency is undergrounding of distribution lines. As explained by Company witnesses Kelly and Jennifer M. Partlan, the work based on its Commission approved pilot to underground LVD lines was completed in 2024 and early 2025. The results of the pilot show that undergrounding yields similar value to customers when compared to alternatives based on a utility cost test and a better value to customers when the comparison is conducted using the alternate methodology of the societal cost test which includes the customer cost of outages. Based upon the findings of

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1 the pilot, the Company has included 50 miles of undergrounding in the test year. Utilizing
2 learnings from the pilot, the Company understands how to identify where undergrounding
3 work is likely to be lower cost. Based on work conducted by peer utilities, the Company
4 continues to expect an improvement in reliability of 90% or more where undergrounding
5 work is performed.

6 **Wildfire Risk Mitigation**

7 The Company is presenting an updated five-year wildfire risk mitigation plan in
8 response to recent events across the U.S. that highlight the prudence of such planning and
9 investment for this high impact event. As described by Company witness Kelly, the
10 Company is continuing the work approved in Case No. U-21585 including activities related
11 to situational awareness, operational procedures, and vegetation management to address
12 wildfire risks.

13 **IRM**

14 As described later in this testimony, the Company's support and proposed
15 continuation of the Commission-approved IRM reinforces the Company's commitment to
16 distribution system reliability and resiliency. This proposed IRM includes two additional
17 programs critical to customers and reliability. The Repetitive Outages – LVD program
18 addresses issues causing customers to experience four or more outages a year. The
19 Company has not met the Commission's standards in this area and the investment dollars
20 included in the IRM are meant to improve performance in this space. Specifically, the
21 dollars are designed to identify locations on the system where customers experience
22 frequent outages and correct the underlying issues. The other additional program is the
23 Vulnerable Communities Resiliency Plan. This program is crucial for ensuring

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1 disadvantaged communities receive better than average all-weather reliability. The
2 inclusion of these programs in the IRM shows the Company's commitment to ensuring
3 improvement in the number of customers experiencing frequent outages and equitable
4 treatment for vulnerable customers. The IRM discourages the Company from shifting
5 investment dollars away from these critical system investments and provides refunds to
6 customers in the event of underspending.

7 **Service Restoration Resiliency Fund and Extraordinary Storm Accounting ("ESA")**

8 As detailed in the direct testimony of Company witness Snider, the Company is
9 proposing a Service Restoration Resiliency Fund and ESA that ensure every dollar
10 collected from customers for service restoration is used for that purpose or refunded to
11 customers and ensures sustainable service restoration operations during extraordinary
12 storms.

13 The Service Restoration Resiliency Fund operates as a reserve of surplus service
14 restoration dollars from any prior year that will be used as the first source of funds when
15 actual costs for service restoration exceed base spend levels. This proposed fund will be
16 capped at \$30.7 million in the test year, with any dollars exceeding those levels refunded
17 to customers through a bill credit. As described by Company witness Snider, the Company
18 is also committed to continued efforts to create service restoration efficiencies. This fund
19 will ensure that efficiency gains flow back to customers.

20 The ESA provides for deferred accounting for service restoration costs for
21 significantly severe storms that exceed base spend levels and cause at least 300,000
22 customer outages over a seven-day period or storms that qualify for a State of Emergency
23 declaration. Storms of this nature are the main cause of increased service restoration

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1 spending and pose the largest risk to sustainable service restoration efforts. There needs to
2 be preparation in the form of the ESA for a future where weather events like the
3 March/April 2025 storms, described by Company witness Snider, are more frequent. The
4 ESA will ensure that service restoration operations during extraordinary events are
5 completed to best serve customers.

6 **Q. How do the proposals in this case support the Company's generation asset strategy**
7 **and commitment to Michigan's clean energy transformation?**

8 A. The Company's Clean Energy Plan demonstrates that the Company can cost-effectively
9 accelerate its timeline to transition away from coal. Company witnesses Richard T.
10 Blumenstock and Thomas P. Clark offer further details about Consumers Energy's
11 generation asset strategy and projected performance considering the Clean Energy Plan,
12 planned investments in natural gas, battery energy storage systems, and hydroelectric
13 generation. While this case does not request recovery of renewable energy related costs,
14 Company witness Blumenstock does discuss the impact of PA 235 of 2023 ("PA 235") on
15 the future renewable energy portfolio indicating that the Company has filed a Renewable
16 Energy Plan Amendment that provides a plan to comply with the renewable energy
17 standards established in PA 235. The Company's Renewable Energy Plan Amendment
18 shows the Company's commitment to meeting the 50% renewable portfolio standard by
19 2030 established PA 235. The Company will concentrate investment in new renewable
20 energy resources and continue investment in the existing gas-fired units as this strategy
21 will provide the greatest long-term customer benefit.

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1 **Q. Please describe recent events impacting the retirement of the Campbell plant.**

2 A. On May 23, 2025, the U.S. Department of Energy issued Order No. 202-25-3 (“DOE
3 Order”) requiring Consumers Energy to continue operating the Campbell plant beyond
4 May 31, 2025. The Company is coordinating with MISO and complying with the DOE
5 Order. The costs presented in this electric rate case have not been adjusted to reflect the
6 impacts of the DOE Order. Consumers Energy plans to request recovery of the costs
7 associated with the DOE Order through a FERC process, as provided by the DOE Order
8 and federal law.

9 **Q. Are hydroelectric investments a component of the Company’s electric generation**
10 **strategy?**

11 A. The Company is evaluating its long-term strategy for the river hydro units. Pursuant to a
12 settlement agreement in the Company’s electric depreciation case, Case No. U-20849, and
13 a filing extension approved in Case No. U-21873, Consumers Energy is planning to present
14 a retirement and decommissioning analysis by the end of 2025. The Company will evaluate
15 each facility and determine the best path forward from the perspective of Consumers
16 Energy, its customers, and the state of Michigan. Although this analysis has not been
17 completed, continued investment in safety and reliability upgrades are necessary to operate
18 the river hydro facilities and to comply with applicable law. However, the Company has
19 not included any associated capital spending in this case as a result of a request to continue
20 deferred accounting treatment for any such spending addressed in detail later in this
21 testimony. Company witness Blumenstock explains that a request for proposal (“RFP”) was issued in February of 2024 to identify potential buyers for the Company’s 13 river
22 hydro facilities. Negotiations related to this RFP are ongoing with an expectation that a
23

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1 contract with a buyer could be achieved during 2025. If the Company is unable to reach
2 an agreement for the sale of the river hydros or if the Commission does not approve the
3 sale, the Company would revisit the decision to relicense or decommission.

4 **Q. Does the Company's electric rate case application include a proposal related to IT**
5 **and security?**

6 A. As described in detail by Company witness Stacy H. Baker, the Company is beginning a
7 critical upgrade to its SAP system that has a direct tie to being able to keep Company and
8 customer information safe and secure. Company witness Daly addresses the Company's
9 proposal for recovery related to the SAP S4/HANA project. Mr. Daly makes proposals
10 that would allow for all costs of the project to be collected from customers over the life of
11 the SAP S4/HANA project assets. First, he recommends that O&M expense related to the
12 project be deferred and amortized over the life of the SAP S4/HANA assets explaining that
13 if this proposal is approved the revenue deficiency of the case could be lowered by
14 \$14.6 million. Mr. Daly also supports the extension of the amortization period to 15 years
15 for the cloud implementation costs for the SaaS solution creating consistency in the
16 recovery for all aspects of the SAP S4/HANA project.

17 **Environmental Justice**

18 **Q. Does the Company's case include Environmental Justice ("EJ") Considerations?**

19 A. Yes. Company witnesses Kelly and Partlan provide discussion on both electric reliability
20 and resiliency in EJ communities, and how these communities are considered in Company
21 investments via Consumers Energy's distribution planning process. Company witness
22 Kelly also describes the Vulnerable Communities Resiliency Plan initiated with a goal of
23 ensuring that no EJ circuits experience worse than industry average reliability. The

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Company has also presented results of EJ regression analysis data in the case providing additional transparency around EJ reliability performance. These items included in the case demonstrate the Company's commitment to equity in utility service.

Customer Impacts

Q. Please quantify the overall rate increase if the Commission approves the entirety of the rate relief requested in this case.

A. Consumers Energy's rate request equates to an overall rate increase of 9.2% excluding the distribution deferral surcharge. The requested increase is 9.7% including the distribution deferral surcharge.

Q. What actions has the Company taken to mitigate the customer bill impacts of the investment plans described in this case?

A. Customers' ability to fund the investments in the Company's system is complemented by Consumers Energy's continued focus on cost savings. The Company's continued efforts to improve productivity and reduce costs will allow Consumers Energy to deliver on its necessary investments for customers and keep customer bills affordable.

Q. How will the Company's rate request affect the typical residential customer?

A. The Company expects that with the increase proposed in this case, the typical residential electric customer will pay on average about \$4.87 a day for electricity during 2026. In her direct testimony, Company witness Laura M. Connolly explains the rate design details.

The Company understands that this increase will challenge some customers. Recognizing the challenges some customers face, the Company offers a range of assistance options, including the Consumers Affordable Resource for Energy Program, a Residential Income Assistance credit, and a Low-Income Assistance Credit for qualifying customers.

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The Company and its employees are also contributors of both time and money to community based groups including the United Way, the Salvation Army, and many other local service organizations.

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 direct testimony on behalf of Consumers Energy in this filing:

- **Stacy H. Baker** supports the IT Departments, capital expenditures, and O&M expenses that are needed to maintain existing IT systems, enable new security capabilities, and support other technology needs as proposed in the case. Ms. Baker also describes the Company's capital spending and O&M expenses related to cyber security operations and physical security.
- **Marc R. Bleckman** supports the Company's proposed capital structure and cost of capital which should be used in computing the overall rate of return. In addition, Mr. Bleckman provides additional support for short-term debt, projected cash balances, and support for the treatment of the line clearing ramp-up costs.
- **Richard T. Blumenstock** provides an overview of the Company's current generation assets and supports the Company's generation asset strategy including unit retirement dates and plans to maintain safe and environmentally compliant operations of coal plants until retirement, periodic outage plans, generation unit availability, capital expenditures, O&M expenses, employee retention program costs, and a description of environmental regulations for the Company's electric generating fleet. Mr. Blumenstock also describes the evaluation of the long-term strategy for the river hydro facilities.
- **Eugène M.J.A. Breuring** supports the Company's electric revenues, deliveries, generation requirements, and peak demand in the test year.
- **Ann E. Bulkley** supports the Company's proposed Return on Equity that should be used in computing the overall rate of return.
- **Jessica R. Byrom** describes the work performed by the Company's Customer Experience & Operations organization and how this work benefits customers. Ms. Byrom also supports the capital investment and O&M expense associated with executing this work.

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- **Thomas P. Clark** provides background, updates, and support for capital expenditures associated with new Battery Energy Storage System projects.
- **Laura M. Connolly** presents the Company's rate design proposals, including an enhancement to its economic development tariff, a coincident peak provision on the General Primary Demand rate, and a change to applying power factor credits and penalties.
- **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.
- **Patrick D. Daly** presents the historic and test year revenue deficiency, including the treatment of various regulatory assets and liabilities. Mr. Daly also presents the projected test year revenue requirement for Demand Response ("DR") programs and requests related to distribution capital deferrals. In addition, Mr. Daly proposes deferrals related to the line clearing ramp-up and SAP S4/HANA.
- **Emily A. Davis** sponsors the Company's electric cost-of-service study that conforms to methods previously approved by the Commission. She also provides support for calculating the state reliability mechanism charge and substation ownership credit and the DR and IRM surcharges.
- **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, and the request for certain accounting approvals.
- **Alex M. Gast** describes the Company's DR program, associated costs and proposed updates. Mr. Gast also makes a proposal to exclude DR from rate cases going forward and instead have the review of projected DR spending take place in the annual reconciliation case.
- **Brittani A. Gray** presents the Company's proposed tariff language changes to its electric rate schedules.
- **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 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 expenditures and O&M expenses related to the Electric business portion of Facility Operations and Shared Services.

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Mr. Guinn also describes the function and needs of the Company's fleet services and supports the fleet investment.

- **Megan L. Hayward** describes and provides the benefits of the Company's HVD lines system, HVD and LVD substations, Metro system, and System Protection assets, and supports the associated capital investments.
- **Michael P. Kelly** provides an overview of the Company's electric distribution strategy and presents an amended Reliability Roadmap using the Reliability Roadmap as filed in Case No. U-20147 as a starting point. Mr. Kelly also explains the Company's distribution strategy and corresponding future investment levels. He outlines the current state and performance of the Company's electric distribution system and how the investments requested in this case will impact reliability. Mr. Kelly also supports the O&M expenses for the electric distribution organization, aside from Line Clearance and Service Restoration.
- **Jon J. Koetje** presents actual 2024 decommissioning and coal ash disposal costs for D.E. Karn ("Karn") Units 1 and 2 and J. H. Campbell ("Campbell") Units 1, 2, and 3 and provides updated projected decommissioning expenses for Karn Units 1 and 2 and Campbell Units 1-3.
- **Scott A. McPhail** provides an overview of the Company's Grid Automation plans and supports the associated capital expenditures.
- **Ashley E. Meschke** supports the Company's requested recovery for EICP employee compensation costs. Ms. Meschke also discusses operational performance goals included in the Company's EICP and how the EICP goals provide benefits to customers.
- **Megan L. Metz** supports PSCR costs expected during the test year and provides the Company's state reliability mechanism capacity charge inputs, cost offsets, demand, and reconciliation. Ms. Metz also provides an update on Midcontinent Independent System Operator, Inc.'s Seasonal Adequacy Construct and supports the value of continued investment in the Company's generation assets and DR programs. Ms. Metz also supports the value of upgrades to the PCI Energy Solutions software.
- **Jeffrey A. Myrom** proposes enhancements to the Transportation Electrification Plan.
- **Jennifer M. Partlan** explains the Company's projected capital costs for the LVD system and the corresponding benefits of these investments.

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- **Daniel A. Schmoekel** provides an overview of the Company's streetlighting assets and the strategic plan for management of those assets. Mr. Schmoekel also supports capital expenditures for streetlighting infrastructure. Mr. Schmoekel also discusses the Company's streetlight outage restoration performance.
- **Andrew R. Snider** supports the Company's service restoration spending, including the proposal of a resiliency fund and extraordinary storm accounting, and the capital costs for the Control/Dispatch Center consolidation.
- **Sara E. Stewart** provides an overview of the Company's line clearing program and the Company's proposal to increase spending to ramp up to achieve a five-year effective LVD line clearing cycle while continuing to maintain HVD's four-year line clearing cycle.
- **Caitlin M. Tetrick** supports the operational workforce resources necessary to support the capital investments and O&M spending in LVD and HVD.
- **Brian J. VanBlarcum** supports the Company's property tax rate as well as the excess deferred federal income taxes being returned to electric customers because of the Tax Cuts and Jobs Act of 2017, the Company's Calculation C proceeding.

CASE REQUIREMENTS

Q. Has the Company addressed in this filing the requirements for its next electric rate filing included in the Commission's U-21585 Order?

A. Yes. The following is a list of requirements for Consumers Energy's next electric general rate application included in the U-21585 Order, with the Company witnesses who address the topics:

HVD New Business – The U-21585 Order included a requirement to identify equipment generally needed for distributed energy resource and electric vehicle interconnections, such as transformers, that currently have a long-lead time for procurement and propose a plan for maintaining an adequate inventory of that equipment to support future development. Company witness Kelly addresses this requirement.

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1 **LVD Repetitive Outages** – The U-21585 Order included a requirement to present a robust
2 case to demonstrate that dollars from the LVD Repetitive Outages subprogram were spent
3 on addressing reliability in LVD repetitive outages. Company witness Partlan addresses
4 this requirement.

5 **AMI Opt-Out Charges** – The U-21585 Order included a requirement to reevaluate
6 advanced metering infrastructure opt-out charges to ensure alignment with the cost of
7 service and present the results of this evaluation. Company witness Kelly addresses this
8 requirement.

9 **Hydro Deferral** – The U-21585 Order included a requirement that the approved deferral
10 for hydro was subject to review in the next rate case. This requirement is addressed later
11 in my testimony.

12 **Electric Vehicles** – The U-21585 Order included a requirement to provide an update on
13 each transportation electrification plan enhancement approved by the Order along with
14 lessons learned. Company witness Myrom addresses this requirement.

15 **Cost Rates** – The U-21585 Order included a requirement to (1) explain and justify the size
16 and expense associated with short-term borrowing facilities if only a very small portion is
17 being or has been utilized and (2) provide a more thorough explanation of renewables
18 liability short-term debt process, consistent with the Commission Staff’s recommendations
19 in that case. These requirements are addressed by Company witness Bleckman.

20 **Sales Forecast** – The U-21585 Order included a requirement to provide both historical and
21 forecasted sales on both a cycle-billed and calendar basis; provide the 60-months of most
22 recent actual historical, weather normalized historical, and projected sales in the same level
23 of granularity. This requirement is addressed by Company witness Breuring.

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1 **Forestry** – The U-21585 Order included a requirement to provide an analysis of the
2 feasibility of more aggressive line clearing. The Order also required that Consumers
3 Energy incorporate the findings of its Formal Optimization Analysis of Line Clearing
4 Cycles into its forestry line clearing operations and maintenance approach and spending
5 proposal, while also considering the benefits of shifting to a four-year fixed tree trimming
6 cycle. This requirement is addressed by Company witness Stewart.

7 **EICP** – The U-21585 Order included a requirement to provide more support and
8 explanation regarding the coordination of operations between gas and electric businesses
9 to justify how the Company can expect electric business employees to achieve the methane
10 emission reduction goals labeled under the “Environmental” category. This requirement
11 is addressed by Company witness Meschke.

12 **Environmental Justice** – The U-21585 Order included a requirement to present an EJ
13 Resiliency Plan with specified proposed investments and a regression analysis which
14 includes data on residential disconnections. This requirement is addressed by Company
15 witness Kelly.

16 **State Reliability Mechanism** – The U-21585 Order included a requirement to include a
17 reconciliation calculation for the state reliability mechanism. This requirement is
18 addressed by Company witnesses Davis and Metz.

19 **Productivity Offsets to Inflation** – The U-21585 Order directed the Company to present
20 more detailed evidence in the next rate case to demonstrate that it is offsetting inflation by
21 productivity gains. Several witnesses address how the Company is using productivity gains
22 to mitigate cost increases. I will also address this requirement later in my testimony.

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Customer Outreach – The U-21389 Order included a requirement to continue holding customer outreach events soon after the filing of an electric rate case. This outreach allows an opportunity for customers to provide feedback and provides customers with information on this filed rate case as well as customer assistance information. While not specified in the U-21585 Order, Consumers Energy will continue to hold these customer outreach events. The outreach event for this filing is scheduled for June 26, 2025 from 4 p.m. to 7:30 p.m. at Martin Luther King Jr. Recreation Center, 1107 Adrian Street, Jackson, Michigan 49201.

DISTRIBUTION IRM

Q. Is the Company proposing a Distribution IRM in this case?

A. Yes. The Company proposes to continue the use of the Distribution IRM. The Commission most recently approved a Distribution IRM in Case No. U-21585 covering the 12-month ending February 28, 2026. In this case, the Company is proposing an IRM that will cover a two-year period beginning May 1, 2026, consistent with the start of the test year of this case. Consumers Energy proposes to continue the IRM using the same investment categories approved by the Commission in Case No. U-21585 with the addition of two new sub-programs: Repetitive Outages, and Vulnerable Communities. Company witness Kelly discusses these additional sub-programs in his testimony. Further, the Company proposes that the spending levels included in the IRM for the 12 months ending April 30, 2027 be set at test year levels approved for each program in this case and year 2 of the IRM should be equal to year 1 spending levels.

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1 **Q. What level of expenditures has the Company included in the IRM?**

2 A. As further discussed in the testimony of Company witness Kelly, the included expenditure
3 levels are summarized in Table 2 below.

Table 2: IRM Expenditures

Sub-Program/ Investment Category	Proposed IRM Expenditures
Lines Reliability - LVD	\$276,191,000
Resiliency Fractionalization –	\$11,647,000
System Protection	\$4,098,000
Repetitive Outages - LVD	\$30,344,000
Vulnerable Communities	\$30,000,000
Total	\$352,280,000

4 **Q. How does the IRM provide customer and stakeholder benefits?**

5 A. The Distribution IRM provides for the recovery of select distribution capital spending
6 programs while allowing for customer protections and additional opportunities for
7 collaboration and review. The proposed IRM includes some of the investment programs
8 that are critical for distribution system reliability. The previously approved IRM programs
9 of Lines Reliability - LVD, Resiliency, and System Protection target improvements critical
10 to reducing major event days. The Repetitive Outage program is specifically designed to
11 identify locations on the system where customers experience frequent outages and correct
12 the underlying issues. The Vulnerable Communities program is crucial for ensuring
13 disadvantaged communities receive better than average all-weather reliability. The IRM
14 process, as discussed below, will provide customer protections and ensure the spending on

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1 these important programs are spent at approved levels to achieve the reliability benefits
2 they support.

3 **Q. Does the Company propose to maintain the same IRM process approved in Case No.**
4 **U-21585?**

5 A. Yes. The IRM process inclusive of the planning meetings, reporting metrics, and
6 reconciliation process, as approved in Case No. U-21585, should be applied to the
7 requested IRM in this case.

8 **Q. What benefits does the IRM process provide to customers?**

9 A. The IRM and the associated process provides customer protections, transparency,
10 collaboration, and increased accountability for distribution investments. Customers will
11 benefit from the certainty of investments in the capital programs included in the IRM that
12 are critical to improved reliability. In addition, the reconciliation process will ensure
13 customers do not pay to support investments if they are not actually made. The IRM brings
14 additional transparency and accountability to project planning and results through
15 reconciliation filings, collaboration on IRM project planning, and reporting on the
16 execution of those plans. The distribution spending proposed for inclusion in the IRM
17 represents further commitment by the Company to the reliability and resiliency of the
18 electric distribution system as well as a commitment to provide equitable service to
19 customers in our most vulnerable communities. The IRM ensures that approved spending
20 on critical investments is spent on those investments. The reconciliation process for the
21 IRM, by line item, provides a strong incentive for the Company to complete the IRM
22 spending as included in the IRM surcharge and not shift dollars between programs.

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1 **Q. Please describe the proposed IRM surcharge for the 12 months ending April 30, 2027**
2 **and the 12 months ending April 30, 2028.**

3 A. The calculation of the revenue requirement for the IRM, inclusive of the proposed increase
4 in capital spending, is included in Exhibit A-163 (HJM-1). This annual revenue
5 requirement is then used by Company witness Connolly to provide an allocation of the
6 revenue requirement by rate class and to remove the IRM revenue requirement from the
7 calculation of base rates to calculate the IRM surcharge by rate class for the test-year.

8 **Q. How will base rates be impacted if the Commission adjusts the capital spending**
9 **included in the IRM?**

10 A. If the Commission adjusts the capital spending included in the IRM, base rates will need
11 to be adjusted and designed to recover the revenue requirement of any capital spending not
12 included in the IRM.

13 **RIVER HYDRO DEFERRAL**

14 **Q. Is the future of the River Hydro facilities uncertain?**

15 A. Yes. As discussed by Company witness Blumenstock, the river hydros may be divested,
16 decommissioned, or relicensed for continued operations. The Company is in negotiations
17 for the potential sale of the River Hydro assets. However, if the sale does not materialize
18 or if a sale agreement is not approved by the Commission or Federal Energy Regulatory
19 Commission, the Company would have to revisit the decision to either decommission or
20 relicense for continued operation.

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1 **Q. Has the Commission addressed the uncertainty of the River Hydro facilities in a prior**
2 **rate case?**

3 A. Yes. In Case No. U-21585 the Commission approved the deferral of the revenue
4 requirement of capital spending associated with the river hydros stating:

5 “The Commission finds that, due to the uncertainty of the
6 disposition of the 13 river hydros as discussed by the parties,
7 and rather than approve or disallow the capital expenditures
8 that Consumers proposed in this rate case, the company may
9 use deferred accounting of the revenue requirement on actual
10 capitalized investments incurred subject to review in the
11 Company’s next rate case.”

12 **Q. Given the continued uncertainty of the disposition of the River Hydro facilities, how**
13 **does the Company propose to treat capital and O&M expense in this case?**

14 A. The Company proposes the continued use of deferred regulatory accounting through the
15 test year of this case for the revenue requirement on actual capital spending incurred related
16 to the River Hydros. As a result, the Company has removed the rate base impact associated
17 with the 2024 historical capital spending and has not included any projected capital
18 spending in the case. O&M expense needed to safely operate the hydro units has been
19 included in the case. If actual O&M expense is lower than amounts included in rates, the
20 Company proposes to defer the difference to a regulatory liability for refund to customers.
21 The proposed treatment of the capital and O&M related to the River Hydros will provide
22 the time needed to understand the future of the River Hydros while ensuring that customers
23 are not asked to pay for investments or operating expenses that are not actually incurred.

PRODUCTIVITY OFFSETS TO INFLATION

Q. The Commission, in its order in Case No. U-21585, directed the Company to present more detailed evidence in the next rate case to demonstrate that it is offsetting inflation by productivity gains. How do you respond?

A. While the Company is committed to transparency and rigor in its economic analyses, it faces significant challenges in isolating and quantifying the precise impact of productivity gains as an offset to inflationary pressures, especially for productivity gains that have not been realized at the time of filing the rate case. Productivity improvements often manifest in indirect or diffuse ways—such as through process efficiencies, technological integration, or workforce optimization—that are not easily captured in traditional financial metrics or short-term reporting frameworks.

It is important to acknowledge that productivity does not always manifest itself as dollar reductions but is often the creation of more efficient outputs or rather the ability to provide more to customers with the same amount of costs. These complexities make it difficult to present granular, standalone evidence that definitively attributes cost containment or margin stability to productivity gains alone. As a result, while the Company can point to broader trends and strategic initiatives aimed at enhancing efficiency, the nature of these improvements does not lend itself to the kind of detailed, itemized documentation required to show productivity gains by line item in witness exhibits. The absence of such detail should not be interpreted as a lack of effort or effectiveness in managing inflationary impacts through productivity.

Further, development of projected costs for many of the programs is more complex than simply applying an inflation factor to historical costs. Each Company witness

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1 supports the costs they are sponsoring in this case and the methodology used to develop
2 those costs. For example, Company witness Stewart describes how the Company uses
3 historical costs plus changes to programs to develop projected test year costs for Line
4 Clearing and includes details of how the costs were projected in her testimony. Ms. Stewart
5 also explains that clearing more frequently reduces unit cost (cost per mile) to maintain the
6 LVD system and that Forestry contains costs through contractually limited inflation
7 increases. Ms. Stewart states that all contractor rates are contractually limited through
8 mid-2029 to an annual adjustment of a minimum of 0.0% per year up to a maximum of
9 2.5% per year based on the Producers Price Indices WPUFD4 and WPU443.

10 Company witness Baker describes the method used to project IT Operations O&M,
11 and explains that inflation is not used to project any categorical spend projections for IT
12 Operations O&M expenses, other than labor. She also includes details about key drivers
13 for changes in costs, including resource efficiencies that offset projected labor cost
14 increases, cost optimization efforts in contracts for cloud subscriptions, and license and
15 maintenance agreements and decreases in Non-Labor Other costs based on reductions in
16 business expenses. Ms. Baker also explains that IT does not apply inflation for categorical
17 spend projections for Investments Planning expenses or for IT Investments O&M
18 expenses.

19 Company witness Byrom explains that Customer Experience & Operations'
20 projected expenses are developed using zero-based budgeting. This means that all
21 expenses must be justified for a new period or year starting from zero, versus starting with
22 the previous budget and adjusting it as needed. She also describes initiatives that have
23 resulted in reduced costs for customers.

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1 Company witness Blumenstock describes how Generation O&M is projected and
2 discusses efficiencies that have limited cost increases in the projected test year.

3 Company witness Snider explains how the projected test year service restoration
4 costs were developed and discusses the Company's increasing service restoration
5 efficiencies.

6 Company witness Foster describes how Adjusted Corporate Services O&M
7 expense was calculated and describes a reduction to projected test year O&M due to
8 insurance distributions.

9 Company witness Guinn describes how the Company projects its facilities
10 maintenance expense and real estate expense and maintains the O&M expense growth at
11 or below the rate of historical plus the current inflation factor year over year.

12 **Q. Please summarize your direct testimony.**

13 A. Consumers Energy respectfully submits this request for \$436 million in annual rate relief,
14 and collection of \$24 million associated with the deferred costs related to distribution
15 investments made during the 12 months ended February 28, 2025. As explained in this
16 testimony, the requested rate relief can be reduced by \$36 million if the proposed deferrals
17 for line clearing ramp up costs and expense related to the SAP S/4/HANA project are
18 approved. Consistent with Consumers Energy's deeply held commitment to provide
19 exceptional value and service to every customer, caring for the communities where we live
20 and work, and delivering on investor expectations, the Company is requesting revenue
21 recovery for infrastructure investments that primarily support the Clean Energy Plan, the
22 Reliability Roadmap, as well as other programs, including the distribution IRM, that will
23 benefit customers. The Company is also continuing its efforts to minimize the increase in

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1 O&M expense through productivity improvements, first time quality, and reducing
2 employee safety incidents. Consumers Energy is committed to customer value and
3 improving customer service and believes that this filing is a representation of the
4 commitment put forth in the Company's purpose – World Class Performance Delivering
5 Hometown Service.

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

7 **A.** Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

REDACTED
DIRECT TESTIMONY
OF
STACY H. BAKER
ON BEHALF OF
CONSUMERS ENERGY COMPANY

June 2025

STACY H. BAKER
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1 **Q. Please state your name and business address.**

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

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

6 A. I have worked for the Company for over 25 years in various individual contributor and
7 leadership positions. The first nine years were in the Finance Department as an Accounting
8 Analyst performing responsibilities to support Payroll and Accounts Payable and later as
9 the Payroll Manager during the Systems, Applications, and Products in Data Processing
10 (“SAP”) implementation. Thereafter, I moved to the Information Technology (“IT”)
11 Department where I have held a number of positions including Enterprise Resource
12 Planning (“ERP”) Portfolio Manager, Director of Business Relationship Management –
13 Corporate Services, and Executive Director of IT Business Technology – Corporate
14 Services. In these roles I focused on technology supporting corporate areas of the
15 Company and had IT departmental responsibility for the delivery and operation of IT
16 applications for Finance, Human Resources (“HR”), Supply Chain, Legal and Government,
17 Regulatory & Public Affairs. I am currently the Director of Technology Portfolio Office
18 responsible for portfolio management of the Company’s IT, Security, and Operational
19 Technology (“OT”) assets, project management office including agile services, project
20 delivery organization, technology vendor management, and organizational change
21 management. This includes the management of the IT long-term financial plan,
22 administration of portfolio management, cloud financial management, development of
23 testimony and exhibits, and supporting rate cases for the IT Department.

STACY H. BAKER
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1 **Q. Would you please state your educational background?**

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

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

6 A. Yes. I testified in the following cases:

- 7 • Case No. U-21308 – 2022 Gas Rate Case;
- 8 • Case No. U-21490 – 2023 Gas Rate Case; and
- 9 • Case No. U-21806 – 2024 Gas Rate Case.

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

11 A. The purpose of my direct testimony is to describe the Operating and Maintenance
12 (“O&M”) expenses and capital expenditures needed by the IT Department to maintain and
13 secure existing IT and security systems and enable new capabilities and services to support
14 safety, reliability, and resiliency. I also provide an overview of increasing threats in both
15 Cyber Security and Physical Security areas, their evolution over time, and the changing
16 regulatory landscape that necessitates increased O&M funding. These increases are
17 essential for advancing cloud computing solutions, maturing security capabilities, and
18 protecting the Company’s technology and physical infrastructure.

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

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The benefits of increasing technology use for customers, and the Department's support of the Company's commitments outlined in the Integrated Resource Plan ("IRP") and Electric Distribution Infrastructure Investment Plan ("EDIIP"), will also be highlighted. Lastly, the importance of achieving full recovery of the requested expenses and expenditures to provide the best value to the Company's customers will be demonstrated.

Q. Please summarize the main portions of this testimony.

A. My direct testimony discusses the following:

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

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- Cost benefit ratio calculated by the Company's internal Business Planning System ("BPS");
- Individual project synopses and requests to support electric and customer plans;
- Individual project synopses and requests to support corporate functions crucial to running an efficient business;
- Individual IT project synopses with supporting, detailed exhibits for the Asset Refresh projects and the Application Currency projects;
- Individual IT project synopses with a supporting, detailed exhibit (Exhibit A-24 (SHB-9) for Enhancement projects, along with a detailed worklist of the enhancement work backlog found in Exhibit A-25 (SHB-10);
- Individual IT project synopses for the IT/Digital Foundations and Capabilities projects;
- Further information about and justification of several larger and more complex projects for which projected spending varies from amounts forecasted in Case No. U-21585, including the following projects:
 - Asset Refresh Program ("ARP")-Field Device Asset Management ("FDAM"),
 - ARP-Printer Asset Management ("PAM"),
 - ARP-Workstation Asset Management ("WAM"), and
 - SAP High-performance ANalytic Appliance ("HANA") Database Migration;
- Explanation of the changes to ARP – Cyber Security, subdividing it into the following new ARP projects relevant to this case:
 - ARP-Cyber-Common, and
 - ARP-Cyber-Electric;
- Explanation of the changes to ARP-Local Area Network, ARP-InfoBlox, and ARP-OT Electric, consolidating them into the following new ARP projects:
 - ARP-Network-Common; and
 - ARP-Network-Electric;
- Further information on the actual costs for projects which had disallowances in Case No. U-21585:

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- IT Operations Management – Service Operations,
- Operational Technology – Service Management Upgrade,
- Software Asset – Service Management Upgrade, and
- SolarWinds Performance Monitoring Expansion Upgrade; and
- Further information about and justification of the more complex SAP S/4HANA Implementation project.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

Exhibit A-17 (SHB-1)	Summary of Actual and Projected Information Technology Operations O&M Expense for the Years 2024, 2025, 2026, and Test Year 12 Months Ending April 30, 2027;
Exhibit A-18 (SHB-2)	Historical and Projected 13-Month Average of IT Cloud Computing Prepaid Balance for the historical years 2024 - 13-month balance ending December 31, 2024, and for the projected years 2026 – 13-month balance ending April 30, 2027;
Exhibit A-19 (SHB-3)	Summary of Actual and Projected Information Technology Investments O&M Expense for the Years 2024, 2025, 2026, and Test Year 12 Months Ending April 30, 2027;

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1	Exhibit A-12 (SHB-4)	Schedule B-5.1	Projected Capital
2			Expenditures Information
3			Technology Summary of
4			Actual and Projected Electric
5			and Common Capital
6			Expenditures;
7	Confidential	Exhibit A-20 (SHB-5)	Synopses Containing
8			Descriptions, Scope,
9			Benefits, Implementation
10			Dates and Detailed Costs of
11			Actual and Projected Electric
12			& Common Capital
13			Expenditures and O&M
14			Expenses for the Years 2024,
15			2025, 2026, and 2027;
16	Confidential	Exhibit A-21 (SHB-6)	Business Case Executive
17			Summaries for Historical,
18			Bridge Period, and Test Year
19			Projects;
20		Exhibit A-22 (SHB-7)	Asset Refresh Programs
21			Projected Electric and
22			Common Capital
23			Expenditures, For the
24			Projected Year 2026 and Test
25			Year Ending April 30, 2027,
26			and For the Historical and
27			Projected Years 2024 and
28			2025;
29	Confidential	Exhibit A-23 (SHB-8)	Application Currency
30			Programs Projected Electric
31			and Common Capital and
32			O&M Expenditures for the
33			Years 2026, 2027, and Test
34			Year 12 Months Ending
35			April 30, 2027;
36		Exhibit A-24 (SHB-9)	Projected Versus Actual
37			Enhancement Capital
38			Expenditures and O&M
39			Expense Summary and
40			Analysis;

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Exhibit A-25 (SHB-10)

Enhancement Worklist Detail
for Years 2016 through
October 21, 2024; and

Confidential Exhibit A-26 (SHB-11)

Projected 13-Month Average
of IT S/4HANA Cloud
Implementation Costs for the
projected years 2026 –
13-month balance ending
April 30, 2027.

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 consistently provide and maintain reliable, secure, simple, and intuitive digital solutions and services that support the delivery of business objectives, including execution of the Company's IRP and EDIIP. Inherent in those objectives are the Company goals to provide exceptional service to its customers by supplying safe, reliable, affordable, clean, and equitable energy.

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

- Executing work in an efficient and effective manner while remaining flexible as deliverables change by adopting agile frameworks, platforms, and product-centric operating models that allow the Company to adjust to changing demands on the IT system;
- Equipping coworkers with digital skills through training that enables them to deliver business value faster to ensure the Company meets customer expectations;
- Moving to cloud solutions where and when appropriate to reduce cost, improve security, and increase the speed of providing new capabilities;

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- Treating data as an asset and deploying analytics on a larger scale for effective decision making, optimization of existing assets, and efficient investment prioritization;
- Deployment of a consistent asset management system and integrated control systems to reduce risk, optimize and digitize processes, and monitor the health of the system to identify necessary preventative maintenance that reduces waste and long-term costs;
- Ensuring customer data is safe and secure, their privacy is protected, and both critical technology assets as well as critical infrastructure assets are secure; and
- Managing security risks and mitigating associated threats.

Q. Have there been any changes to the IT functions that are new in Case No. U-21870?

A. Yes. The following changes have been integrated in my direct testimony and exhibits: (1) the Security Department is part of the IT Department and no longer represented by a separate witness; (2) the Company has integrated the analytics function (Analytics and Outreach) that was part of the Customer Interactions function into the IT Department; and (3) the Company has also integrated the analytics function that was a part of the Process, Analytics & Technology function, within Operations Performance, into the IT Department. These changes, new in Case No. U-21870, better centralize the Company's technology expenditures and expenses.

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

Q. Please describe the functions the IT Department performs.

A. The IT Department provides reliable, secure, and simple digital solutions and services to the Company's customers and internal business units. This includes identification,

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1 delivery, operational support, and maintenance of both on-premise and cloud software
2 solutions and computing and communications infrastructure and analytics to support
3 customer safety and reliability. The IT Department also provides the day-to-day
4 operational support for coworkers using technology, whether that technology is a desktop,
5 laptop, or mobile device (e.g. ruggedized field device, tablet computer, cell phone,
6 smartphone, or other handheld device).

7 The scope of the IT Department also includes OT. OT is the set of real-time
8 industrial control systems that monitor and control the Company's critical electric
9 infrastructure, such as the Electric Supervisory Control and Data Acquisition ("SCADA")
10 systems.

11 Additionally, the scope of the IT Department includes Security. This includes
12 emergency management, physical security, and cyber security. Security exists to deter
13 threats prior to impacting the Company, detect when malicious activity does occur, recover
14 quickly with minimal effect if or when a threat is successful in causing impact, and comply
15 with all governmental and industry regulations. Security sets standards based on external
16 threats and guides security work required by the IT and OT teams.

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

18 A. Technology is an integral part of all aspects of the Company's electric strategy from
19 generation all the way to the customer. The Company is leading a clean energy
20 transformation by accelerating the Company's exit from coal-fired generation while
21 increasing electric reliability and resiliency for customers. To realize this plan, the
22 Company needs to invest in new technology as the future of energy generation is
23 increasingly more distributed and complex. As the Company increases investment in

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1 demand response, energy efficiency, and grid modernization tools, these virtual “power
2 plants” will help the Company reduce energy demand and manage customer load
3 efficiently and effectively. The continued addition of solar energy sources, wind energy
4 sources, and battery storage to the generation landscape will also require the utilization of
5 technology systems to operate and manage them safely, effectively, and efficiently.

6 The Company’s EDIIP is its roadmap to reliability that is driven by investments in
7 a modern distribution system to safely deliver clean, affordable, and reliable power to
8 customers throughout Michigan with a goal of fewer and shorter power outages. The
9 Company’s plan for a reliable and resilient modern electric grid requires technologies to
10 support the electric devices, communications, and analytics for advanced capabilities like
11 Volt-VAR Optimization and Conservation Voltage Reduction that advance energy
12 efficiency and peak demand reduction. The Company’s plan also relies on technology to
13 enhance electric reliability and resiliency through Fault Location, Isolation, and Service
14 Restoration, as well as enabling initiatives for Distributed Energy Resources, like solar and
15 wind generation, and energy storage systems.

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

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

2 A. A big challenge the IT Department currently faces is the integration and implementation
3 of emerging technologies, data, and analytics needed to achieve the Company's goals
4 described in the IRP and EDIIP. The Company relies heavily on accurate data and high
5 performing systems that can handle higher transaction and data volumes. Customers
6 depend on these same systems to report outages, receive timely information on the
7 estimated time of restoration, and view the outage map including impacted areas. It is
8 important that the Company achieve full recovery of requested expenses and expenditures
9 to keep these systems updated with the latest security and maintenance patches while
10 delivering new capabilities to help restore customers faster.

11 Another challenge is that security continues to be a significant risk area and
12 challenge for utilities. Traditional physical security issues of protecting publicly
13 accessible, geographically dispersed critical infrastructure are and will continue to be
14 exacerbated as resources become more distributed. Cyber security concerns include
15 privacy, data breaches, ransomware, ransom extortion, denial of service, and critical
16 infrastructure attacks. For example, a February 7, 2024 Cybersecurity Advisory from the
17 Cybersecurity and Infrastructure Security Agency ("CISA") states that the CISA, National
18 Security Agency, and Federal Bureau of Investigation assess that People's Republic of
19 China ("PRC") state-sponsored cyber actors are seeking to pre-position themselves on IT
20 networks for disruptive or destructive cyberattacks against U.S. critical infrastructure in
21 the event of a major crisis or conflict with the United States.¹ The U.S. authoring agencies
22 have confirmed that the PRC state-sponsored cyber group known as Volt Typhoon has

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

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1 compromised the IT environments of multiple critical infrastructure organizations -
2 primarily in Communications, Energy, Transportation Systems, and Water and Wastewater
3 Systems Sectors - in the continental and non-continental United States and its territories,
4 including Guam.

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

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

19 **A.** Cyber threats are increasing. The most glaring example is ransomware as discussed above.
20 These threats have increased, not only in their impact but also their level of sophistication.
21 Criminal groups are profiting on ransomware, and it has become such a lucrative business
22 that they now conduct cyberattacks in a more sophisticated manner with teams of people

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1 who focus on an individual target. Such groups are more focused on Fortune 500
2 companies because of the potential for large ransom payments.

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

14 Beyond ransomware, nation-state actors have a strong interest in United States
15 critical infrastructure. The federal government has repeatedly called out this risk and has
16 been imploring critical infrastructure owners to increase their capabilities. On July 28,
17 2021, the Biden Administration released a memo titled “National Security Memorandum
18 on Improving Cybersecurity for Critical Infrastructure Control Systems” (“July 28
19 Memo”).² The implications of the National Security Memo are clear.

20 First, the threat to critical infrastructure is real and no longer theoretical. Even the
21 Company has seen intrusion attempts from nation-state level actors. The July 28 Memo
22 provided that “[t]he cybersecurity threats posed to the systems that control and operate the

² Available at <https://bidenwhitehouse.archives.gov/briefing-room/statements-releases/2021/07/28/national-security-memorandum-on-improving-cybersecurity-for-critical-infrastructure-control-systems/>.

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1 critical infrastructure on which we all depend are among the most significant and growing
2 issues confronting our Nation.”

3 Second, cyber security of critical infrastructure is a national security issue and
4 priority. The July 28 Memo explained that “[t]he degradation, destruction, or malfunction
5 of systems that control this infrastructure could cause significant harm to the national and
6 economic security of the United States.” Utilities have had strong cyber security programs,
7 and the Company is no different. However, by calling out cyber security of critical
8 infrastructure as a national security issue, the Biden Administration signaled that the
9 Company, as an owner of critical infrastructure, should meet an even higher standard
10 moving forward. The National Security Memo suggested that utilities need to have
11 capabilities matching those of the top government agencies and contractors. This increased
12 expectation will take time to develop and increased funding to achieve.

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

18 As for the Trump Administration, it recently issued an executive order suggesting
19 that it may shift responsibility for investments in cybersecurity and other critical
20 infrastructure to state and local governments. In doing so, the White House recognized
21 that “[c]itizens are the immediate beneficiaries of sound local decisions and investments
22 designed to address risks, including cyber attacks, wildfires, hurricanes, and space

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1 weather.”³ Thus, the White House continues to support further investment in
2 cybersecurity, even if state and local governments are ultimately asked to assume more
3 responsibility. The executive order directed federal officials to reevaluate national critical
4 infrastructure policy, including several National Security memorandums, but the July 28
5 Memo was not on the list of memorandums being reviewed.

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

7 A. Cyber security receives much of the national headlines because it is a relatively new risk
8 and does not require physical proximity to execute an attack. However, physical security
9 risks are still extremely relevant in the critical infrastructure space, and they continue to
10 evolve. In the past year, there have been several incidents that pose risks to the stability of
11 the electric grid. These include theft, equipment damage, vandalism, and intentional
12 gunfire aimed at disrupting the grid.

- 13 • **Copper Theft:** Thieves target substations, transformers, and other electrical
14 infrastructure due to the high resale value of copper, which causes substantial
15 damage and disrupts power supply.
- 16 • **Transformer Damage:** Damaged transformers can leak oil, posing
17 environmental hazards. Tampering with high-voltage equipment can also lead
18 to explosions or fires.
- 19 • **Gunfire Incidents:** In the mid-Michigan area, there have been incidents where
20 gunfire was aimed at critical electric infrastructure, intending to disrupt service.

21 These types of incident present challenges in maintaining a reliable and safe electricity
22 supply.

³ Presidential Actions, *Achieving Efficiency Through State and Local Preparedness*, THE WHITE HOUSE (March 29, 2025), <https://www.whitehouse.gov/presidential-actions/2025/03/achieving-efficiency-through-state-and-local-preparedness/>.

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

3 A. The very nature of certain utility assets makes them very challenging to secure. Large
4 assets such as a headquarters building or power plants can be secured using traditional
5 physical security measures such as video cameras, card access, fencing, locks, keys, gates,
6 and guards. The smaller, more distributed assets are significantly more challenging to
7 secure. Placing guards at each asset would be untenable from a cost perspective.
8 Technology solutions have historically been challenging because of limited feature sets
9 (enhancements and capabilities) and network capacity at many of these remote locations.
10 These limitations have led utilities to implement basic physical protections and accept
11 remaining risk. Responses to security issues in these environments are, therefore, reactive
12 and have become insufficient. These factors have made these critical assets soft targets to
13 those who would do harm intentionally and attractive for opportunistic crimes. A shift to
14 a more proactive approach will minimize the impacts to customers from outage, safety, and
15 cost perspectives. The Company continues to be proactive in its approach to better protect
16 its assets and increase safety.

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

18 A. The current cyber and physical regulatory landscape is highly uncertain. The current
19 administration aims to reduce regulatory oversight, but their position on cyber and physical
20 security and its national security implications remains unclear. The recent executive order
21 indicates that the administration may propose more state control over these areas.
22 Regardless, the Company anticipates a continued push for more cyber incident reporting
23 and mandatory standards in electric distribution, whether driven by federal or state

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1 authorities. The industry is expecting additional mandatory cyber security standards across
2 the regulatory landscape.

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

5 A. Yes. The Company has new NERC/CIP requirements for electric systems. While gas
6 focused, the TSA (Transportation Security Administration) security directives also affect
7 the Company's corporate systems, which are a part of this case.

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

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

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

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

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

18 **Q. Is the Company migrating to the cloud and what are the advantages of leveraging**
19 **increased cloud capabilities?**

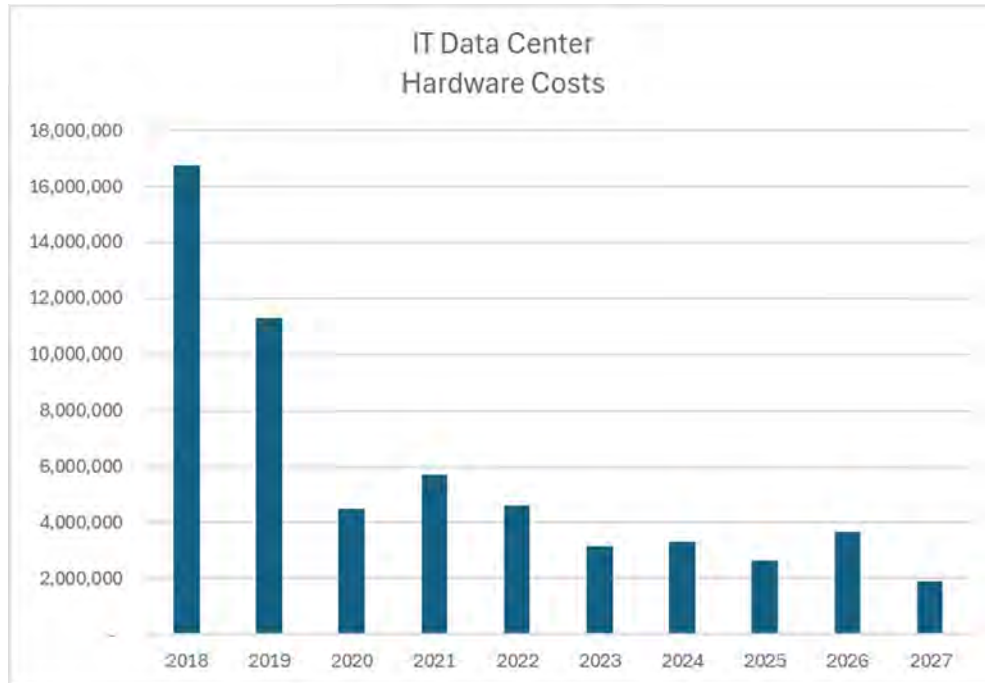
20 A. Yes, the Company is migrating most of its IT data center to cloud-based services.
21 Leveraging increased cloud capabilities offers several advantages, including the ability to
22 scale capacity, pay only for resources that are used, avoid capital investment and O&M

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1 expense for hardware and maintenance, enhance security, and employ built-in backup and
2 recovery solutions.

3 First, cloud capabilities offer scalability, enabling the Company to easily adjust
4 their computing resources based on demand. This allows the Company to increase or
5 decrease capacity as needed, unlike traditional data centers that would require longer
6 implementation times. For example, during peak periods like storm response, the
7 Company can quickly scale up resources to handle increased traffic. Conversely, during
8 off-peak periods, cloud resources can be reduced to optimize costs.

9 Second, cloud capabilities also offer cost efficiencies by only paying for the
10 resources that are used. It reduces the Company's capital expenditures in physical
11 hardware and the associated ongoing maintenance costs, as well as the cost of a physical
12 location. The Digital-Hybrid Cloud and Data Center Migration project, which began in
13 2022, has enabled the Company to avoid the capital investment for IT data center hardware
14 asset refresh based on a five- to seven-year refresh cycle, as shown in the table below. This
15 initiative includes migrating or retiring applications out of existing Company and
16 co-location data centers into cloud services.



1 Third, cloud capabilities offer advance security features and regular updates to
2 protect sensitive data, ensuring compliance with industry standards and regulations.

3 Fourth, the Company's owned data center is aging and beginning to have challenges
4 with operational stability. Moving to the cloud allows the Company to avoid the large
5 capital expense of building a new data center.

6 Finally, cloud capabilities offer reliable backup and disaster recovery solutions
7 through redundant infrastructure to ensure high availability and reliability, minimizing
8 downtime and providing consistent access to services.

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

12 **A.** The Company's critical security and operational fixes are given priority over new
13 capabilities to ensure safe, secure, and reliable operation of its digital assets. There is a
14 high demand for new and enhanced technology capabilities across the Company. New

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1 investments are prioritized based on an evaluation of the benefits, costs, customer value,
2 and necessity to Company goals through a series of reviews by cross-functional business
3 teams. The highest-ranking projects are approved through the Company's budget and rate
4 case processes and ultimately implemented.

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

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

12 **IT OPERATIONS O&M EXPENSES—MAINTAIN AND OPERATE**
13 **EXISTING ASSETS**

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

15 A. The Company uses IT Operations O&M expense to provide the required level of
16 operational support, reliability, and security for technology investments; maintenance for
17 security facilities and systems to ensure system reliability, vulnerability assessments, and
18 penetration tests; and fulfillment of all state and federal laws and regulations, perimeter
19 protection, guards, card access, cameras, executive protection, and investigative services.
20 IT Operations O&M expenses include fixed and variable ongoing costs. Fixed costs
21 include software vendor maintenance agreements, cloud subscription contracts, annual
22 license contracts, and application or appliance support through managed services contracts.
23 Software and cloud solution vendors typically increase these fixed costs on an annual basis.
24 Variable costs include labor for equipment monitoring, break/fix activity, maintenance

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1 activity, disaster recovery, security improvements, software patching, and cloud usage
2 costs. Operations costs also include physical security site assessments, vulnerability and
3 penetration test remediation, additional guard support, system break/fix or maintenance
4 activity, privacy program maturity, staffing support to meet emerging regulatory laws and
5 regulations, and additional security system improvements. The activities associated with
6 the fixed and variable costs are required to keep the Company's digital, information, and
7 physical assets protected and performing at sufficient levels. The Company's customers
8 benefit from the system stability and reliability that result from the activities funded by IT
9 Operations O&M expense. These activities include emergency response, 24/7 billing,
10 payment and usage services, contact center support, new service installations, and various
11 other digital offerings, as well as physical and cyber security activities. Any unrecovered
12 IT Operations O&M cannot be recovered in future rate case filings, which is why any
13 disallowance could impede the Company's ability to maintain and secure its facilities and
14 systems.

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

17 A. There is a variety of operational work required to keep information and physical assets
18 protected from cyber threats. First, regarding information assets, security tools must be
19 kept functional when they are called on to protect the technology vital to serving the
20 Company's customers. This technology includes software to collect logs, scan for
21 vulnerabilities, detect intrusions, and provide antivirus and encryption services. Second,
22 IT resiliency must be kept up to date ensuring backup data and redundant infrastructure are
23 in place in the event of a cyber intrusion. Third, as described previously, systems must be

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1 patched on a regular basis in accordance with security requirements. Vendors regularly
2 release security updates that must be tested to ensure these updates do not introduce
3 negative impacts to Company-specific configurations when deployed. Fourth, as cyber
4 security standards and requirements change, IT teams must implement the appropriate
5 corresponding technical changes on existing systems to ensure Company assets remain
6 secure. These requirements evolve and adapt as threats change in our environment.
7 Security regularly reviews and updates physical and cyber security standards to maintain
8 the appropriate posture with various industry frameworks, as well as compliance with cyber
9 security regulations. This includes the technical requirements for IT to follow, which
10 increases operational costs while continuing to best protect Company assets

11 Regarding physical assets and employee safety, first, routine assessments must be
12 performed on all assets and facilities to ensure proper maintenance is performed and
13 security protections are properly placed including perimeter protection, cameras, and card
14 readers for facility access. Second, additional security support is needed for employees
15 when threats are present near field project work, storm restoration activities, or Company
16 sponsored public events or forums. Third, additional security guard support is needed at
17 facilities on an ad hoc basis (based on intelligence collected from facilities or crews, threats
18 of violence against the Company, increased protest activity as seen in 2020, increased
19 contractor traffic, and potential employee issues) to ensure the safety of employees and any
20 visitors to the Company's facilities.

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

2 A. Foundational technologies, such as infrastructure, user devices, and collaboration tools,
3 play a crucial role in supporting the systems that deliver services to the Company's
4 customers.

5 Infrastructure includes physical and virtual systems that support all Company
6 operations. These systems are essential for running critical applications, managing data,
7 and maintaining communication that ensure efficient and reliable service to customers.
8 User devices provide workers access to real-time data, help manage work, and facilitate
9 communication to serve customers. Collaboration tools enable workers to collaborate
10 effectively, address issues efficiently, and share information to serve customers.

11 Further, foundational technology systems support predictive analytics and machine
12 learning algorithms that can forecast demand and identify potential issues before they
13 become critical, allowing for proactive maintenance and response. Additionally, these
14 systems support the integration of renewable energy sources, enabling a more sustainable
15 energy supply.

16 Customers are required to provide certain types of data as part of the service
17 provided to them and want to know that the Company has a world class cyber security
18 program working to protect data provided. Data breaches can cause identity theft,
19 fraudulent charges, and time lost addressing related associated impacts. Beyond data
20 breaches, customers also expect their data to be handled properly and only for the purposes
21 intended. The discipline which addresses these concerns is broadly referred to as privacy,
22 which is also within the corporate responsibility of the IT Department. In addition to
23 data-related concerns, customers expect the Company's core services to be available 24/7.

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1 This is relevant on both the corporate and operational sides of the business. A ransomware
2 attack would limit the service the Company can provide to customers and could lead to
3 delays in resolving issues, obtaining service, outages, or significant safety concerns. An
4 attack against the Company's operational systems could lead to a protracted loss of
5 electricity or natural gas service for large portions of the service territory. Interruption of
6 gas or electric service due to a cyberattack is not acceptable, and customers expect the
7 utility to have all the protections necessary to ensure this does not occur.

8 In addition, physical security measures are essential in protecting the infrastructure
9 that delivers electricity. This includes securing substations, power plants, and transmission
10 lines from physical threats such as vandalism, theft, and natural disasters. Implementing
11 robust physical security protocols, such as surveillance systems, access control, and
12 perimeter security, helps safeguard these critical assets. By integrating physical security
13 with technological systems, the Company can create a comprehensive approach to
14 protecting the electrical grid and ensuring uninterrupted service to its customers.

15 Together, these foundational technologies and cyber and physical security
16 measures ensure that electricity is delivered efficiently, reliably, and safely to customers.

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

18 A. Exhibit A-17 (SHB-1) is a Summary of Actual and Projected IT Operations O&M Expense
19 for the Years 2024, 2025, 2026, and 12 months ending April 30, 2027. Page 1 summarizes
20 the electric allocation of actual and projected IT Department operational expenses.
21 Specifically:

- 22 • Column (a) provides the IT Operations O&M expense category;
- 23 • Column (b) identifies the total 2024 historical IT Operations O&M expense as
24 \$51,403,000;

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- Column (c) identifies the total 2025 projected IT Operations O&M expense as \$58,460,000;
- Column (d) identifies the total 2026 projected IT Operations O&M expense as \$66,327,000;
- Column (e) identifies the total projected IT Operations O&M expense for the 4 months ending April 30, 2027 as \$22,441,000;
- Column (f) identifies the total projected IT Operations O&M expense for the Test Year as \$66,659,000; and
- “Labor” line items include employee labor; “Contracts” line items include hardware and software licenses and maintenance, and software subscriptions; “Material” line items include individual computer peripherals, tools, supplies, and replacements for failed components such as hard drives; and “Contractor” line items include staff augmentation, the Company’s managed services contracts, and other contracted services. “Non-Labor Other” line items include employee training, wireless plans, and supplies.

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

- Column (a) describes the categorical expense;
- Column (b) provides the historical IT Operations O&M expense;
- Column (c) provides the historical amount that an inflation rate was applied to;
- Columns (d), (f), and (h) provide the inflation increases for each respective period;
- Columns (e) and (g) provide the amount that an inflation rate was applied for 2025 and 2026, respectively;
- Column (i) includes amounts that were projected using other methods; and
- Column (j) provides the projected test year IT Operations O&M and is the sum of columns (b), (d), (f), (h), and (i).

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

A. IT does not apply inflation in all categorical spend projections for IT Operations O&M expense. Labor is the only categorical spend projection that includes a merit increase based

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1 on the inflation rate. Inflation is not used to project any other categorical spend projections
2 for IT Operations O&M expense. Future contract expenses reflect current commitments
3 to increase payments under existing contracts, as well as the addition of new contracts
4 needed for ongoing and new project work taking place before or during the test year.
5 Material and Non-labor Other are projected based on historical spend and known
6 adjustments for employee training needs, wireless plans, and supplies.

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

9 A. The IT Operations O&M expense in 2025 of \$58,460,000 is projected to be an increase
10 over 2024, which is \$47,095,000 for IT and \$11,365,000 for Security. The reason for the
11 increase in 2025 is the result of organizational changes and the necessity to fund continued
12 investment in programs to sustain and improve system reliability; to maintain, improve,
13 and secure critical enterprise systems that support the Company's IRP and EDIIP; and to
14 prevent obsolescence and risk to business operations offset by cost-saving measures. Key
15 drivers for the change from 2024 to 2025 for IT include: (1) net labor increased based on
16 merit increases (\$0.19 million) – transfer of website from Customer Operations and
17 analytics resources from Customer Interactions and Operations Performance (\$0.56
18 million) to IT, increase in resources supporting grid and electric asset management (\$0.33
19 million), backfill of resources supporting analytics (\$0.5 million), and offset by move of
20 network resources to Security (\$0.2 million); (2) increase material costs (\$0.65 million);
21 (3) increase in contractor (\$1.3 million), which a portion (\$0.12 million) is based on the
22 transfer of website contractors costs from Customer Interactions; (4) net increase in
23 contracts for cloud subscriptions and license and maintenance agreements due to cost

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1 optimization efforts offset by annual increases (\$2.1 million); and (5) a decrease in
2 Non-Labor Other (\$0.58 million) based on reduction in business expenses.

3 Key drivers for the change from 2024 to 2025 for Security include: (1) labor
4 increased based on merit increases (\$0.08 million) and increase for resources to support
5 the Fusion Center and move of network resources from IT to Security (\$0.71 million);
6 (2) net increase in contracts for cloud subscriptions and license and maintenance
7 agreements (\$1.2 million) including reductions in MS Azure costs offset by an increase in
8 cloud security platform; (3) increase in contractor (\$0.59 million) based on reduction in
9 Physical Security contractors; and (4) decrease in Non-Labor Other (\$0.5 million) based
10 on reduction in business expenses.

11 **Q. Please describe the projected IT Department IT Operations O&M expense for 2026,**
12 **as reflected in Exhibit A-17 (SHB-1).**

13 **A.** The IT Operations O&M expense in 2026 of \$66,327,000 is projected to be an increase
14 over 2025, which is \$54,964,000 for IT and \$11,362,000 for Security. The reason the
15 Company is projecting an increase in 2026 is the necessity to fund continued investment
16 in programs to sustain and improve customer reliability as the Company continues
17 investing to maintain, improve, and secure critical enterprise systems and migrate
18 applications to the cloud. Known increases that are projected for IT include: (1) net labor
19 increase due to merit increase (\$0.23 million) offset by resource efficiencies; and
20 (2) increase in cloud subscriptions and license and maintenance agreements (\$7.9 million)
21 including costs related to the Genesys Cloud Migration, Standard Work Plan, and Digital-
22 Hybrid Cloud and Data Center Migration projects and additional increases offset by cost
23 optimization efforts to keep costs flat.

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Key drivers for the change from 2025 to 2026 for Security include: (1) net labor increase based on merit increases (\$0.09 million) offset by resource efficiencies; and (2) no change in contracts for cloud subscriptions and license and maintenance agreements due to planned cost optimization efforts to offset increases.

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

A. The IT Operations O&M expense in the test year of \$66,659,000 is projected to be an increase over 2026, which is \$55,297,000 for IT and \$11,362,000 for Security. The reason the Company is projecting an increase in the test year is the necessity to fund continued investment in programs to sustain and improve customer reliability as the Company continues investing to maintain, improve, and secure critical enterprise systems and migrate applications to the cloud. Known increases that are projected for IT include: (1) labor is flat due to merit increase (\$0.08 million) offset by resource efficiencies; and (2) increase in cloud subscriptions and license and maintenance agreements (\$0.34 million), including costs related to the Digital-Hybrid Cloud and Data Center Migration projects.

Key drivers for the change from 2026 to the test year for Security include: (1) labor increase based on merit increases (\$0.03million) offset by resource efficiencies, and (2) no change in contracts for cloud subscriptions and license and maintenance agreements due to planned cost optimization efforts to offset increases.

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

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

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

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

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

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

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

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

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

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

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

21 A. Exhibit A-18 (SHB-2) is the IT Cloud Computing Prepaid Balance for Electric and
22 Common operations for the historical 13 months ending December 31, 2024 and the

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projected 13 months ending April 30, 2027. It provides a summary of the electric allocation of actual and projected IT Department operational expenditures. Specifically:

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

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

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

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

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

A. IT 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 new capabilities for internal business units, security operations, and customers.

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

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

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

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

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

20 A. While the Company's preferred upgrade strategy is to stay, at most, one version behind the
21 vendor's currently available version, the Company considers multiple factors to determine
22 when upgrades are needed. These include application criticality to business and customer
23 operations, severity of existing vulnerabilities and operational risk, operational impacts of

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performing the upgrade, ability to defer, resource availability, organizational change impact, and cost. Deferring an application upgrade for too long has the potential to increase the overall cost of the upgrade since the larger number of differences between versions generally adds complexity and cost to an upgrade effort.

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

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

A. Exhibit A-19 (SHB-3) is a Summary of Actual and Projected IT Investments O&M Expenses for the Years 2024, 2025, 2026, and the 12 months ending April 30, 2027. Page 1 provides a summary of the gas allocation of actual and projected IT Investments O&M expenditures. Specifically:

- Column (a) provides the IT Investments O&M expense category;
- Column (b) identifies the 2024 historical IT Investments O&M expense as \$8,536,000;
- Column (c) identifies the 2025 projected IT Investments O&M expense as \$13,174,000;
- Column (d) identifies the 2026 projected IT Investments O&M expense as \$26,169,000;
- Column (e) identifies the 4 months ending April 30, 2027 projected IT Investments O&M expense as \$8,857,000;

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- Column (f) identifies the Test Year projected IT Investments O&M expense as \$26,303,000;
- For Investments Planning expense, “Labor” line items include employee labor, and “Contracts” line items include hardware and software licenses and maintenance, staff augmentation, and other contracted services; and
- For Investments expense, “Labor” line items include employee labor; “Software” line items include software licenses and maintenance contracts; “Material” line items include hardware purchases and maintenance contracts; “Contractor Costs” line items include staff augmentation, managed services, and other contracted services; “Non-Labor Overhead” line items include overheads; and “Non-Labor Others” line items include pension expense, administrative/general expense, Allowance for Funds Used During Construction (“AFUDC”), and business expenses.

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

- Column (a) is a description of the categorical expense;
- Column (b) provides the historical IT Investments O&M expense;
- Column (c) provides the historical amount that an inflation rate was applied to;
- Columns (d), (f), and (h) provide the inflation increases for each respective period;
- Columns (e) and (g) provide the amount that an inflation rate was applied for 2025 and 2026, respectively;
- Column (i) includes amounts that were projected using other methods; and
- Column (j) provides the projected test year IT 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 \$362,000 for IT and \$4,000 for Security for anticipated decreases in the test year for investments planning activities that directly support business case development and cost estimate refinement for projects

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1 that support the IRP, EDIIP, and other Company long-term plans. Inflation is also not used
2 to project future IT Investments O&M expense. The other adjustments for IT Investments
3 O&M expense of \$17,317,000 for IT and \$816,000 for Security are based solely on
4 expected project costs for the test year as compared to the historical period, as detailed later
5 in my testimony and in **Confidential** Exhibit A-20 (SHB-5).

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

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

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

15 A. No, it is not speculative. Investment planning is a pragmatic process that results in
16 documented technology investment details. The process documentation includes: a project
17 description and description of system functionality, project timelines including expected
18 implementation date and spending plans, project benefits, a description of alternatives
19 considered and rationale behind the decision, and cost benefit ratio, which were required
20 by the MPSC in Case No. U-18238. Other important activities of investment planning are:
21 identifying high-level business requirements, determining whether the functionality
22 needed is already present in the Company’s IT environment, identifying performance and
23 security requirements, working with software vendors and cloud solution providers to

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1 demonstrate the effectiveness and security of their products and services, and developing
2 the business case with project costs and benefits to confirm whether a proposed project
3 should be approved for development and implementation.

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

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

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

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

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

15 **INVESTMENTS CAPITAL EXPENDITURES**

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

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

- 21 • Column (a) provides the business category designation for the capital
22 expenditures:
 - 23 ○ Corporate;
 - 24 ○ Customer;

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- Electric;
- Electric & Gas Shared;
- IT/Digital Foundation; and
- Security.
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 - Column (b) identifies the 2024 historical year capital expenditures as \$44,023,000;
 - Column (c) identifies the 12 months ending December 31, 2025 projected bridge year capital expenditures as \$52,118,000;
 - Column (d) identifies the 4 months ending April 30, 2026 projected bridge year capital expenditures as \$28,191,000;
 - Column (e) identifies the 16 months ending April 30, 2026 projected bridge year capital expenditures as \$80,310,000; and
 - Column (f) identifies the 12 months ending April 30, 2027 projected test year capital expenditures of \$77,719,000.
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 - Column (b) identifies the 4 months ending April 30, 2025 capital expenditures as \$14,378,000;
 - Column (c) identifies the 12 months ending April 30, 2026 capital expenditures as \$65,931,000;
 - Column (d) identifies the 12 months ending April 30, 2027 projected bridge year capital expenditures as \$77,719,000; and
 - Column (e) identifies the 28 months ending April 30, 2027 projected bridge year capital expenditures as \$147,360,000.
- For Investments expenditures, “Labor” line items include employee labor; “Software” line items include software licenses and maintenance contracts; “Material” line items include hardware purchases and maintenance contracts; “Contractor” line items include staff augmentation, managed services, and other contracted services; “Non-Labor Overhead” line items include overheads; and “Non-Labor Others” line items include pension expense, administrative/general expense, AFUDC, and business expenses.

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

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

- 8 • Column (a) provides the year of spending for each line item project;
- 9 • Column (b) identifies the project name associated with each line item capital
10 and O&M expenditure for the applicable year or years;
- 11 • Column (c) identifies the Federal Energy Regulatory Commission (“FERC”)
12 category relative to the line item project’s asset type;
- 13 • Column (d) identifies the Business Category of the project;
- 14 • Column (e) provides a synopsis of the project, including the project description
15 and information on project scope, functionality, and benefits;
- 16 • Column (f) identifies the project’s start date;
- 17 • Column (g) identifies the project’s end date;
- 18 • Column (h) provides the project’s cost/benefit ratio;
- 19 • Column (i) provides the total Company expected project capital costs;
- 20 • Column (j) provides the total Company expected projected O&M costs;
- 21 • Column (k) identifies the project’s estimate type;
- 22 • Column (l) provides the project’s electric portion total capital expenditure for
23 the applicable year or years;
- 24 • Columns (m) through (r) provide the details of categorical spend that sum to
25 the total line item Project Capital Spend for the applicable year or years broken
26 down by:
 - 27 ○ Software costs (m);

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- Material costs (n);
- Labor costs (o);
- Contractor costs (p);
- Non-Labor Overhead costs (q); and
- Non-Labor Other costs (r).
- Column (s) provides the project's electric portion total O&M spend for the applicable year; and
- Columns (t) through (y) provide the details of categorical spend that sum to the total line item Project O&M Spend for the applicable year or years by the following categories:
 - Software costs (t);
 - Material costs (u);
 - Labor costs (v);
 - Contractor costs (w);
 - Non-Labor Overhead costs (x); and
 - Non-Labor Other costs (y).

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

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

- Exhibit A-12 (SHB-4), Schedule B-5.1, is a high-level summary of capital expenditures by year, by business category or product line, and by categorical spend; and
- Confidential Exhibit A-20 (SHB-5) is a more comprehensive exhibit displaying the detail of each project over the four-year time periods of 2024, 2025, 2026, and 2027.

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

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

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

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

- 18 • Header Information section includes project name, the date the report was
19 generated, and BPS identification number. Specifically:
 - 20 ○ Project Name is the name of the project that indicates the project objective;
 - 21 ○ Report Pulled is the date the Executive Summary report was generated from
22 BPS; and
 - 23 ○ Item ID is the unique identifier from BPS.

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- 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:

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- Initiation is the start date of the project Plan phase;
- Project Plan & Scope Definition is the end date of the project Plan phase;
- Final Engineering, Planning & Design is the end date of the Design phase;
- Execution is the end date of the Execute phase;
- In-Service/Go-Live is the project's implementation date; and
- Closeout is the end date of the Close phase.
- Funding Summary section includes a Total Company summary and detailed breakdown of projected categorical spend by year for each project. Specifically:
 - Summary of the Total Cost of Ownership of projected capital expenditures and O&M expense for each project, including ongoing maintenance, where:
 - Cap+COR is the total of all the capital expenditures; and
 - O&M is the total of all the O&M expense for the project implementation and ongoing maintenance.
 - Total Project Cost contains a detailed categorical breakdown for projected capital expenditures and O&M expense for each project, excluding ongoing maintenance, where:
 - Labor includes the internal staffing costs for project implementation;
 - Outside Services includes the external labor and services for project implementation;
 - Business Expenses/Overheads includes costs for items such as training, travel, lodging, and meals and Loadings & Allocations for Corporate Overheads and AFUDC;
 - Employee Benefits includes costs for employee benefits;
 - Material includes costs for hardware purchases;
 - Licenses, Permits & Fees includes costs for software and hardware licenses and maintenance; and
 - Other includes miscellaneous costs.

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- 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.

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

Where

B = Benefits

C = Total Costs

- o For purposes of identifying risk:
 - ☐ Type of Corporate Risk;
 - ☐ Level of impact;
 - ☐ Likelihood of risk; and
 - ☐ Description of risk.
- o And, for purposes of identifying other value:
 - ☐ Type of other value; and
 - ☐ Description of other value.

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

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

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

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

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

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

9 **INVESTMENT IDENTIFICATION, PRIORITIZATION,**
10 **APPROVAL, AND PROJECT PLANNING**

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

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

21 After sponsor approval, individual projects are prioritized based on an evaluation
22 of the benefits, costs, customer value, and necessity to Company goals through a series of
23 reviews by cross-functional business teams. The highest-ranking projects within the level
24 of IT funding approved through the Company's budget and rate case process are selected

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1 for implementation and approved by each business area, followed by approval of the
2 overall IT budget by the senior officer team. Due to the rapid pace of technology change
3 and quickly changing business conditions, emergent projects are identified and vetted
4 through IT and the affected internal business areas throughout the year as business
5 objectives, Company goals, and customer needs and expectations evolve.

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

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

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

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

Year	Projected	Adjusted Projected (20% ROM Adjustment)
2024	\$44,022,631	\$44,022,631
2025	\$56,793,609	\$52,118,163
2026	\$99,164,570	\$84,574,240
2027	\$73,477,399	\$64,007,880
Test Year	\$90,602,180	\$77,718,786

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

13 A. Yes, in Case No. U-20963, MPSC Staff ("Staff") recommended a 20% disallowance for
14 ROM estimates (Case No. U-20963, 6 TR 4081), and the Commission agreed saying that
15 the ROM estimates are akin to contingency costs. The 20% reduction to capital
16 expenditures for all ROM estimate projects used by IT in this case differentiates the
17 Company's ROM estimates from the ROM estimates it used in Case No. U-20963 (in fact,
18 the 20% reduction reflects Staff's position in Case No. U-20963) and further shows that
19 the ROM estimate projects do not include contingency. Contingency is a project

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management best practice to add and reserve a percentage of a project's budget for unforeseen circumstances encountered during the course of the project. Due to previous disallowances, IT estimates do not include contingency. The ROM estimate is (1) intended to cover the full cost of the project rather than a portion, (2) built to address specific scope rather than unforeseen events, and (3) is calculated by technology and subject matter experts for a specific project whereas contingency is a percentage allocation based on an industry percentage value and/or project risk rating.

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

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

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

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

A. All projects included in the test year will have project plans and target dates at levels commensurate with their current phase. Some projects are continuing from an earlier period into the test year and have more definitive project plans for delivery. When the budget is released to a project to begin the official Plan phase, the product team will

1 develop a more specific project plan that includes progressively more detail as the project
2 moves through its different phases. In the case of projects executed using Agile methods,
3 a high-level plan will be developed at the start of the project that includes an estimated
4 number of time-bound delivery cycles, or sprints, in which the targeted scope backlog will
5 be delivered.

6 **INVESTMENT PROJECTS**

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

9 **A.** Costs, descriptions, benefits, alternatives, and other relevant project information for each
10 individual project can be found in **Confidential** Exhibits A-20 (SHB-5) and A-21 (SHB-6).

11 The IT investment projects are grouped into the following areas for explanation in
12 testimony:

- 13 • **Electric and Electric & Gas Shared** projects that enable the IRP and EDIIP
14 for Asset Management; Work Management; System Automation and Control,
15 Security and Privacy; and Advanced Analytics that are necessary components
16 to enable the Company to be an energy partner that customers, regulators, and
17 the people of Michigan can count on to provide a safe, affordable, reliable,
18 clean, and equitable electric system;
- 19 • **Customer** projects that are necessary to enable the Company to comply with
20 regulatory billing changes, improve billing functionality, implement
21 capabilities to assist low-income customers with energy assistance, increase the
22 Company's ability to serve customers within the channel of their choice, and
23 engage customers to enroll in demand response and energy waste reduction
24 programs;
- 25 • **Corporate** projects that support internal departments of the Company are
26 crucial to running an efficient business such as Treasury; Tax; Legal; HR, also
27 known as People and Culture; Governmental, Regulatory and Public Affairs;
28 Supply Chain and Facilities, also known as Operations Support; Finance; and
29 Risk & Compliance;
- 30 • **IT/Digital Foundation** projects create the technology platforms, tools,
31 processes, and frameworks that are required to enable IRP, EDIIP, and

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customer service outcomes. This includes ARP, application currency, upgrade and replacements, and digital and foundation capabilities projects; and

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

IT Projects Enabling Other Areas

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

A. Below are the projects enabling the IRP and EDIIP. Investments in digital capabilities are essential to achieving the Company's IRP and EDIIP business plans 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	Exhibit References
Electric Geographic Information System (GIS) Design Platform Modernization	\$1,476,532	\$1,181,225	\$136,794	M. Kelly	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1
Catastrophic Crewing (CatCrew) Version 2.0	\$351,467	\$281,173	\$57,067	A.Snyder	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1
Electric GIS Utility Network Transformation	\$1,324,225	\$1,059,380	\$519,952	M. Kelly	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1
Integrated Energy Management Platform Optimization	\$1,343,299	\$1,074,639	\$507,797	M. Metz	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1
Service Restoration Artificial Intelligence	\$825,723	\$94,746	\$660,578	A.Snyder	A-12 (SHB-4), line 3 A-19 (SHB-3), line 1

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

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

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	O&M	Exhibit References
Customer Order Service Tracker	\$735,345	\$588,276	\$154,745	A-12 (SHB-4), line 2 A-19 (SHB-3), line 1
Multi-Account Online Account Management	\$893,008	\$714,406	\$185,073	A-12 (SHB-4), line 2 A-19 (SHB-3), line 1

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

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

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

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Test Year O&M	Exhibit References
2025 Union Contract Changes	\$0	\$0	\$99,515	A-12 (SHB-4), line 1 A-19 (SHB-3), line 1
Enterprise Risk Management	\$0	\$0	\$47,135	A-12 (SHB-4), line 1 A-19 (SHB-3), line 1
Self Service Vendor Portal	\$61,629	\$49,303	\$77,930	A-12 (SHB-4), line 1 A-19 (SHB-3), line 1

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

3 **IT/Digital Foundations and Capabilities**

4 **ARP**

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

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

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

- 20
 - Michigan.gov, Information Technology Equipment Life Cycle⁴

⁴<https://www.michigan.gov/dtmb/-/media/Project/Websites/dtmb/Law-and-Policies/Legislative-Reports/FY2023/Sec-829-Report-of-PA-166---IT-Lifecycle-2023.pdf?rev=7b90fd55a9104194aa50e978d570bfec&hash=1A969DADCAF5A71CD5F0746D0DEE08A4>

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

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

- 4 • Column (a) provides the unit description;
- 5 • Column (b) provides the average unit cost;
- 6 • Column (c) provides the total number of units for the specified year;
- 7 • Column (d) provides the total number of units for the specified year;
- 8 • Columns (e) through (f) provide total actual or projected capital expenditures
9 for the specified year;
- 10 • Column (g) provides the total projected capital expenditures for the test year or
11 the total actual electric allocation of capital expenditures for the specified year;
12 and
- 13 • Column (h) provides electric allocation of capital expenditures for the specified
14 year.

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

17 A. Each page of Exhibit A-22 (SHB-7) relates to a different ARP and infrastructure project,
18 which I discuss further below.

19 **Q. Please explain the ARP-Collaboration project.**

20 A. The ARP-Collaboration project has the following synopsis:

- 21 • The **ARP-Collaboration** project requires \$1,153,267 in capital and \$140,683
22 in O&M in the test year.
- 23 ○ **Description:** This project will replace the Company's obsolete or out-of
24 date audio, visual, telephony, and other communication collaborative tools
25 and equipment.
- 26 ○ **Problem Statement:** When collaboration assets used to support customer
27 interactions and business operations are obsolete or out-of-date, they are
28 more difficult to keep current with security updates. The Company also
29 risks asset failure if it does not adhere to a regular refresh cycle.

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- **Objectives:** This project creates value by: (1) ensuring the stability and reliability of the Company's audio, visual, telephony, and other communications systems; and (2) migrating to new collaboration assets.
- **Scope:** The project scope consists of: (1) replacing aging collaboration assets; and (2) installing new collaboration assets to meet evolving business requirements.
- **Alternatives:** The alternatives considered included: (1) continuing to operate collaboration assets beyond a five-year refresh cycle, or (2) refreshing collaboration assets based on a five-year refresh cycle while evaluating the health of the asset and evolving business requirements. The alternative to operate the collaboration assets beyond a five-year refresh cycle was not selected due to the risk that asset failures would cause stability and reliability issues for employees supporting the Company's customers, as vendors do not provide extended support after five years. The Company chose to refresh the collaboration assets based on a five-year refresh cycle and evaluate the health of the asset and evolving business requirements to reduce the risk of impacting the productivity of employees supporting customers.

Q. Do the Company's 2026 projected electric allocation capital expenditures for material costs for the ARP-Collaboration project differ from the \$576,228 projected in Case No. U-21585?

A. Yes. The 2026 projected electric allocation capital expenditures for material costs for the ARP-Collaboration project of \$1,022,838 (**Confidential** Exhibit A-20 (SHB-5), column (n), line 217) are \$446,610 more than the \$576,228 projected in Case No. U-21585 (Exhibit A-88 (SK 6), column (m), line 309).

The difference is due to the call recording system's hardware being end of life and there is risk of failure. Secondly, there is a need to refresh an additional auditorium to improve collaboration capabilities.

Q. Please explain the change made with the ARP-Cyber Security project.

A. Beginning in 2025, the ARP-Cyber Security project is being replaced with ARP-Cyber Security-Common, ARP-Cyber Security-Electric, and ARP-Cyber Security-Gas projects

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to improve the tracking of these assets and better align the projects with the resources performing the work.

- The **ARP-Cyber-Common** project requires \$843,849 in capital and \$11,215 in O&M in the test year.
 - **Description:** This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions.
 - **Problem Statement:** When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates.
 - **Objectives:** This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations.
 - **Scope:** The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three- to five-year hardware lifecycle; and (2) performing application upgrades.
 - **Alternatives** The alternatives considered include: (1) upgrade or replace only those assets identified in the plan. This alternative was not chosen because maintaining a continued refresh cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warranty repair costs; (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.
- The **ARP-Cyber-Electric** project requires \$430,291 in capital and \$17,616 in O&M in the test year.
 - **Description:** This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions.
 - **Problem Statement:** When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates.

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- **Objectives:** This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations.
- **Scope:** The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three- to five-year hardware lifecycle; and (2) performing application upgrades.
- **Alternatives:** The alternatives considered include: (1) upgrade or replace only those assets identified in the plan. This alternative was not chosen because maintaining a continued refresh cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warranty repair costs; (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs..

Q. Please explain the changes made with the ARP-Core Network, ARP-Local Area Network, and ARP-Infoblox projects.

A. Beginning in 2025, the ARP-Core Network, ARP-Local Area Network, and ARP-Infoblox projects have been replaced with ARP-Network-Common, ARP-Network-Electric, and ARP-Network-Gas projects due to the move of network resources to Security. In addition, a portion of the units from the ARP-OT Electric have been moved to these new projects. These changes were made to improve tracking of these assets and better align the projects with the resources performing the work.

- The **ARP-Network-Common** project requires \$549,198 in capital and \$11,177 in O&M in the test year.

- **Description:** This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks shared by Electric and Gas.
- **Problem Statement:** When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to

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support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle.

- **Objectives:** This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks.
- **Scope:** The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices.
- **Alternatives:** The alternatives considered include: (1) continuing to operate on existing 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; or (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.
- The **ARP-Network-Electric** project requires \$51,630 in capital and \$916 in O&M in the test year.
 - **Description:** This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks for Electric.
 - **Problem Statement:** When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle.
 - **Objectives:** This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks.

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- **Scope:** The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices.
- **Alternatives:** The alternatives considered include: (1) continuing to operate on existing 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; or (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.
- The **ARP-OT Support Electric** project requires \$1,084,783 in capital and \$20,142 in O&M in the test year.
 - **Description:** The ARP-OT Support Electric project will replace dated and obsolete servers on a rotating five-year refresh schedule.
 - **Problem Statement:** When OT Assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle.
 - **Objectives:** This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric 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-year refresh cycle; or (2) refresh hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that hardware component failures would cause system reliability and safety issues for customers, as vendors do not provide extended support after five years. The Company chose the alternative to refresh this hardware based on a five-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 Electric SCADA.

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- 1 • The **ARP-OT Support Common** project requires \$42,643 in capital and
2 \$1,062 in O&M in the test year.
 - 3 ○ **Description:** The ARP- OT Support Common project will replace dated
4 and obsolete servers shared by Electric and Gas on a rotating five-year
5 refresh schedule.
 - 6 ○ **Problem Statement:** When OT Assets that are used to ensure the safety
7 and reliability of technology that supports critical electric operations are
8 obsolete or out-of-date, they can be more difficult to keep current with
9 Security updates and run the risk of failure if the Company does not adhere
10 to a regular refresh cycle.
 - 11 ○ **Objectives:** This project creates value by maintaining the currency of the
12 Company's IT infrastructure and the core enterprise software that are
13 utilized to support the operation of the Company's critical electric
14 infrastructure.
 - 15 ○ **Scope:** The program scope consists of: (1) replacement of computer
16 hardware under the program; and (2) installing additional new compute
17 capacity to account for expanding business requirements.
 - 18 ○ **Alternatives:** The alternatives considered included: (1) continue to operate
19 hardware beyond a five year refresh cycle; or (2) refresh hardware based on
20 a five-year refresh cycle along with evaluating the health of the asset and
21 evolving business needs. The alternative to operate hardware beyond a
22 five-year refresh cycle was not selected due to the risk that hardware
23 component failures would cause system reliability and safety issues for
24 customers, as vendors do not provide extended support after five years. The
25 Company chose the alternative to refresh this hardware based on a five-year
26 refresh cycle along with evaluating the health of the asset and evolving
27 business needs to reduce the risk of impacting critical infrastructure.
- 28 • The **ARP-Physical Security** project requires \$1,449,104 in capital and \$7,826
29 in O&M in the test year.
 - 30 ○ **Description:** The ARP-Physical Security, formerly known as Physical
31 Security Asset Refresh, will enhance or replace physical security assets to
32 provide improved visibility and incident resolution related to security
33 concerns.
 - 34 ○ **Problem Statement:** The Company has several thousand physical security
35 asset devices currently in use including security cameras, motion detectors,
36 intrusion detection systems, and card access systems. Current
37 considerations include the lack of integrated solutions for centralized
38 management, situational awareness, real time monitoring, compliance with
39 regulations and guidelines, and faster responses to emergencies and

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incidents. If the Company does not maintain these assets, it could result in the increase of potential security vulnerabilities, associated penalties, and reputational damage.

- **Objectives:** The value provided by completing the project is to: (1) maintain compliance with State and Federal Regulations; (2) reduce redundancies with less of a need for multiple cameras and reducing gaps in functionality; and (3) optimize overall system performance.
- **Scope:** Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) security cameras for monitoring capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems.
- **Alternatives:** Alternatives considered include: (1) not refreshing physical security assets; and (2) defer a portion of the refresh of physical security assets per an asset refresh cycle industry standard. Alternatives 1 and 2 were not selected due to the risk of security concerns, incident resolution, and the inability to meet FERC requirements. The alternative selected maintains compliance, reduces redundancies and gaps in functionality, and optimizes overall performance of physical security systems.

Q. Please explain the ARP-PAM project.

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

- The **PAM** project requires \$237,618 in capital and \$3,099 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.

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- **Scope:** The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle. This does not mean that all printers are replaced after five years – merely that printers are assessed on a five-year cycle for possible replacement.
- **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 would require the printers to be assessed monthly to ensure they are not run to failure, resulting in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company assesses the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company either decommissions, repurposes, leaves in place, or refreshes the printers.

Q. Do the Company's 2025 projected electric allocation capital expenditures for material costs for the ARP-PAM project differ from the \$501,862 projected in Case No. U-21585?

A. Yes. The 2025 projected electric allocation capital expenditures for material costs for the ARP-Collaboration project of \$1,013,149 (**Confidential** Exhibit A-20 (SHB-5), column (n), line 147) are \$511,287 more than the \$501,862 projected in Case No. U-21585 (Exhibit A-88 (SK 6), column (m), line 253).

Q. Please explain why the Company's 2025 projected electric allocation capital expenditures for material costs for ARP-PAM differ from the previous case.

A. The Company's 2025 projected electric allocation capital expenditures for material costs of \$1,013,149 differ for ARP-PAM from the materials projections in the previous case due to the deferral of refreshes of devices from 2020 – 2023. The refreshes were deferred due to resources working remotely due to the pandemic.

Q. Please explain the ARP-FDAM project.

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

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- The **ARP-FDAM** project requires \$4,850,461 in capital and \$3,099 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 before they fail; 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:** Alternatives considered include: (1) using outdated equipment. This alternative was not selected because there would be an increased risk of hardware failure and equipment outages that could impact meter readers' ability to complete job tasks. It would also complicate the Company's efforts to meet the MPSC's meter reading factor and consecutive estimated targets, and it could cause applications to run poorly or stop functioning; (2) The second alternative considered was to replace the hardware. The Company selected this option to alleviate the above concerns.

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

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

- **Replacements:**
 - Are determined by pulling the quantity of device types with a scheduled retirement year:
 - Field devices scheduled retirement year is four years from purchase;
 - The model of device determines the unit cost. The total of these devices with their current unit cost is established for a particular year's budget;

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- Accessories for field devices are projected based on the number of planned replacements and include desk docks, vehicle docks, and ac adapters; and
- Carryover devices are added from the previous year to address aging devices first.

- **New Purchases:**

- Are projected at \$1 million annually.
 - The Company reviews actual historical new purchase costs for the past four years to ensure the \$1 million is reasonable and prudent;
- The costs cover the field devices required for the employee/contractor and associated accessories.

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

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

A. Variances for the ARP-FDAM project are a result of changes to new purchases, scheduled replacements, and incremental unit costs. Starting in 2024, there has been a one-time change for new field device purchases. These devices are now a part of the ARP-FDAM project, rather than the ARP-WAM project. Moreover, there is a change in the replacement of some field devices, which were initially planned under the ARP-WAM project. These devices were included in ARP-FDAM starting in the year 2024 going forward. Exhibit A-22 (SHB-7), page 5, details the devices, number of units, and unit costs for each type of device. Below are summary charts with the variance reasons for each year separated between replacement and new purchase categories.

Replacements

Year	Field Device	Reason for variance
2024 Actual	662	• Field device replacements based on refresh schedule. • 84 field device replacements moved from ARP-WAM to ARP-FDAM.
2025 Plan	480	• Field device replacements based on refresh schedules. • 415 fewer refreshes than planned due to retirement of all G1 version devices, downsizing Marshall training room needs and reduced gas construction needs.

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2026 Plan	1,338	- Field device replacements based on refresh schedule. 215 field device replacements moved from ARP-WAM to ARP-FDAM. 425 field device replacements that were purchased as a part of other efforts in 2022.
2027 Plan	972	Field device replacements based on refresh schedule.

New Purchases

Year	Field Device	Reason for variance
2024 Actual	149	Field devices based on actual new employee/contractors.

1 **Q. Do the Company's 2025 projected electric allocation capital expenditures for material**
2 **costs for the ARP-FDAM project differ from the \$3,387,972 projected in Case No.**
3 **U-21585?**

4 A. Yes. The 2025 projected electric allocation capital expenditures for material costs for the
5 ARP-FDAM project of \$2,172,954 (**Confidential** Exhibit A-20 (SHB-5), line 144,
6 column (n)) is \$1,215,019 less than the \$3,387,972 projected in Case No. U-21585 (Exhibit
7 A-88 (SK-6), column (m), line 252).

8 The following describes the reason for the difference:

- 9 1. Field device replacements decreased \$1.20 million due to fewer refreshes than
10 planned based on retirement of all G1 version devices, downsizing Marshall
11 training room needs, and reduced gas construction needs; and
- 12 2. New purchases electric allocation decreased by \$0.01 million based on current
13 electric allocation factors that are updated annually.

14 **Q. Do the Company's 2026 projected electric allocation capital expenditures for material**
15 **costs for the ARP-FDAM project differ from the \$2,948,011 projected in Case No.**
16 **U-21585?**

17 A. Yes. The 2026 projected electric allocation capital expenditures for material costs for the
18 ARP-FDAM project of \$5,136,183 (**Confidential** Exhibit A-20 (SHB-5), line 218,

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column (n)) is \$2,188,172 more than the \$2,948,011 projected in Case No. U-21585 (Exhibit A-88 (SK-6), column (m), line 310).

The following describes the reason for the difference:

1. Field device replacements increased by \$0.72 million due to 215 field devices moved from ARP-WAM to ARP-FDAM;
2. Field device replacements increased by \$0.29 million due to 88 field devices that were initially purchased for training in 2022;
3. Field device replacements increased by \$1.13 million due to 337 field devices that were initially purchased as a part of an Electric and Gas Operations effort in 2022;
4. Field device replacements increased by \$0.02 million due to an increase in unit cost for CF55 field devices; and
5. Labor and Non-Labor Other increased by \$0.03 million to support the increase in number of field device replacements.

Q. Please explain the ARP-Radio project.

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

- The **ARP-Radio** project requires \$1,029,710 in capital and \$133,351 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, vehicle consoles in service trucks, other communications equipment, and associated test equipment. 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 10-year lifecycle basis. Cellular modems are refreshed on a five-year life cycle basis. Amplification systems are refreshed on a 10-year life cycle.
 - **Problem Statement:** 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 and cellular systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing or becoming obsolete. The refresh of this equipment 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

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concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which risks life safety.

- **Objectives:** This project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of capturing audio recordings; and (6) remaining in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure.
- **Scope:** The project scope consists of: (1) scheduled replacement of radios, modems, and consoles; 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 include: (1) Replacing the existing units with new units from other radio and modem manufacturers; (2) Purchasing new radio subscriber units from existing manufacturers. Option 2 was not selected because the Company now uses a standards-based radio system allowing for multiple radio manufacturer options. Option 1 was selected to allow for a competitive bidding process that will provide the most cost-effective radio that will meet the needs of users.

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

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

- The **ARP-Server and Storage** project requires \$323,576 in capital and \$24,131 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

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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.

Q. Please explain the ARP-WAM project.

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

- The **ARP-WAM** project requires \$4,395,889 in capital and \$39,776 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

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

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

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

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

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

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

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

5 • **Replacements:**

- 6 ○ Are determined by pulling the quantity of device types with a scheduled
7 retirement year:
 - 8 ■ PC devices scheduled retirement year is four years from purchase, and
 - 9 ■ Monitors scheduled retirement year is eight years from purchase.
- 10 ○ The model of device determines the unit cost. The total of these devices
11 with their current unit cost is established for a particular year's budget;
- 12 ○ Accessories for PC devices are projected based on the number of planned
13 replacements and include keyboards, surge protectors, docks, backpacks,
14 and cables; and
- 15 ○ Carryover devices are added from the previous year to address aging
16 devices first.

17 • **New Purchases:**

- 18 ○ Are projected at \$1 million annually.
 - 19 ■ The Company reviews actual historical new purchase costs for the
20 past four years to ensure the \$1 million is reasonable and prudent;
- 21 ○ The costs cover the PC devices required for the employee/contractor and
22 associated accessories.

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

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

26 A. Variances for the ARP-WAM project are a result of changes to new purchases, scheduled
27 replacements per four-year PC device and eight-year monitor refresh cycles, previous year
28 deferrals for equipment replacements primarily due to disallowances, and incremental unit
29 costs. Starting in 2025, there has been a one-time change for new field device purchases.

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These devices will now be a part of the ARP-FDAM project, rather than the ARP-WAM project. Moreover, there is a change in the replacement of some field devices, which were initially planned under the ARP-WAM project. Exhibit A-22 (SHB-7), page 15, 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
2024 Actual	1,839	0	138 fewer PC devices replaced due to reduction in resources and reduction of shared PC devices, such as kiosks and lab devices. 233 Desktop replacements deferred to 2025 due to resource availability. - No monitor replacements planned since monitors' eight-year replacement cycle was completed from 2018-2021. The next monitor replacement is targeted to resume in 2027.
2025 Plan	2,968	0	233 Desktop replacements deferred from 2024 due to resource availability. 218 PC devices that are not planned to be replaced due to reduction in resources. - No monitor replacements planned since monitors' eight-year replacement cycle was completed from 2018-2021. The next monitor replacement is targeted to resume in 2027.
2026 Plan	2,196	0	No monitor replacements planned since monitors' eight-year replacement cycle was completed from 2018-2021. The next monitor replacement is targeted to resume in 2027.
2027 Plan	2,159	4,318	Monitor replacements based on an eight-year replacement cycle.

New Purchases

Year	PC Device	Monitor	Reason for variance
2024 Actual	323	331	Based on actual new employee/contractor volume.

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1 **Q. Do the Company's 2024 actual electric allocation capital expenditures for material**
2 **costs for the ARP-WAM project differ from the \$4,260,099 projected in Case No.**
3 **U-21585?**

4 A. Yes. The 2024 actual electric allocation capital expenditures for material costs for the
5 ARP-WAM project of \$3,993,657 (**Confidential** Exhibit A-20 (SHB-5), column (n),
6 line 56) are \$266,442 less than the \$4,260,099 projected in Case No. U-21585 (Exhibit
7 A-88 (SK-6), column (m), line 177).

8 The following describes the difference:

- 9 1. Desktop replacements decreased by \$0.81 million due to fewer requests for
10 desktops, reduction in resources and shared devices, and deferral of desktop
11 replacements to 2025, as discussed above;
- 12 2. Laptop replacements increased by \$0.64 million due to more requests for these
13 devices;
- 14 3. Accessories decreased by \$0.07 million; and
- 15 4. New PC purchases decreased by \$0.03 million based on actual hiring.

16 **Q. Do the Company's 2025 projected electric allocation capital expenditures for material**
17 **costs for the ARP-WAM project differ from the \$5,896,927 projected in Case No.**
18 **U-21585?**

19 A. Yes. The 2025 projected electric allocation capital expenditures for material costs for the
20 ARP-WAM project of \$5,646,692 (**Confidential** Exhibit A-20 (SHB-5), column (n),
21 line 148) are \$250,235 less than the \$5,896,927 projected in Case No. U-21585 (Exhibit
22 A-88 (SK-6), column (m), line 255).

23 The following describes the difference:

- 24 1. Desktop replacements increased \$0.39 million due to deferral of replacements
25 from 2024 to 2025, as discussed above;

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2. Laptop and tablet replacements decreased by \$0.40 million based on reductions in resources;
3. Accessories decreased by \$0.38 million due to decrease in laptop and tablet replacements, as described above; and
4. New purchases electric allocation decreased by \$0.01 million based on current electric allocation factors that are updated annually.

Q. Do the Company's 2026 projected electric allocation capital expenditures for material costs for the ARP-WAM project differ from the \$4,609,542 projected in Case No. U-21585?

A. Yes. The 2026 projected electric allocation capital expenditures for material costs for the ARP-WAM project of \$4,013,510 (**Confidential** Exhibit A-20 (SHB-5), column (n), line 221) are \$596,032 less than the \$4,609,542 projected in Case No. U-21585 (Exhibit A-88 (SK-6), column (m), line 313).

The following describes the difference:

1. Laptop and tablet replacements increased by \$0.25 million based planned replacements;
2. Monitors decreased by \$0.86 million, as they were inadvertently planned for 2026 and should not have been planned until 2027, per eight-year refresh cycle for monitors.;
3. Accessories decreased by \$0.02 million due to decrease in monitors, as described above; and
4. New purchases electric allocation decreased by \$0.01 million based on current electric allocation factors that are updated annually.

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

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1 associated systems. The Company performs security risk and various types of technical
2 analysis to determine which applications need upgrading or replacing and when. Upgrade
3 and replacement projects are created for larger and more complex application and platform
4 upgrades or replacements that require increased oversight and project management.
5 Smaller upgrades are aggregated by IT product line and spend type in the Application
6 Currency projects.

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

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

- 9 • The **Asset Accounting Tax Upgrade** project requires \$65,865 in O&M in the
10 test year.
 - 11 ○ **Description:** The project will upgrade the Company's current accounting
12 asset management tax software to the SaaS version as required by the
13 vendor ensuring continued support of a critical financial application and
14 providing new functionality.
 - 15 ○ **Problem Statement:** In 2025, standard vendor support ends for the current
16 on-premise PowerTax software. Losing vendor support creates security and
17 stability risk that can result in performance issues. When the application is
18 out of the normal support with the vendor, the Company no longer receives
19 security patches, support for defect resolution or bug fixes, and cannot
20 enhance the application. To ensure compliance with regulated and financial
21 accounting in the fixed asset sub-ledger, it is necessary to perform an
22 upgrade and maintain vendor support. In addition, the upgrade provides
23 additional functionality to increase the frequency of financial reporting and
24 improve visibility.
 - 25 ○ **Objectives:** This project creates value for the Company by ensuring
26 compliance with regulated and financial accounting within the fixed asset
27 sub-ledger. In addition, the project adds value by: (1) moving to a SaaS
28 solution in order stay supported; and (2) reducing security, stability, and
29 performance risk by ensuring consistent, seamless vendor support.
 - 30 ○ **Scope:** The project scope includes: (1) evaluating current vendor/product
31 solutions with market leaders; and (2) upgrading the vendor software from
32 the current version to the newer SaaS version or replacing it.
 - 33 ○ **Alternatives:** Alternatives considered include: (1) evaluating other
34 software options. This option would introduce new ongoing support costs

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and integrations and may not provide regulatory reporting and other needed improvements. (2) do nothing and remain on unsupported, on-prem tax solution. This option would introduce costly technical and financial risks. (3) upgrading to the newest SaaS version of current on-prem solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

- The **Asset Accounting Upgrade 2025-2026** project requires \$27,444 in O&M in the test year.
 - **Description:** The project will upgrade the Company's current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application.
 - **Problem Statement:** Standard vendor support will be ending 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. There are also larger costs to upgrade if the upgrades are further apart due to complex testing activities and too many version increases at any one time.
 - **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; (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support; and (4) lowering costs with more frequent upgrades to reduce testing complexities and reduce the number of versions to be adopted.
 - **Scope:** The project scope includes: (1) evaluating current vendor/product solutions with market leaders; and (2) upgrading the vendor software from the current version to the newer version.
 - **Alternatives:** Alternatives considered include: (1) evaluateing 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) evaluating other software options. This option would

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introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements.(3) upgrading to the newest version of the 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 **Asset Accounting Upgrade 2027-2028** project requires \$115,263 in O&M in the test year.

- **Description:** The project will upgrade the Company's current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application.

- **Problem Statement:** Standard vendor support will be ending 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. There are also larger costs to upgrade if the upgrades are further apart due to complex testing activities and too many version increases at any one time.

- **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; (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support; and (4) lowering costs with more frequent upgrades to reduce testing complexities and reduce the number of versions to be adopted.

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

- **Alternatives:** Alternatives considered include: (1) evaluating 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) evaluating other software options. This option would introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (3) moving to cloud option. This option would be expensive and has an unclear timeline.

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(4) waiting until a future upgrade cycle. This option introduces technical risk. (5) upgrading to a newer version of the current solution. This is the preferred option as it will provide more frequent software 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 2027 Upgrade** project requires \$76,842 in O&M in the test year.

- **Description:** Axway SecureTransport is the official Consumers Energy multi-protocol Managed File Transfer (“MFT”) gateway for securing, managing, and tracking data file flow for 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 SecureTransport is the public-facing MTF 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 the Company, its customers and business partners by: (1) addressing known problems and limitations of the current software platforms; (2) ensuring continued secure, scalable, and critical data transmission services running through Axway; (3) creating the capacity to methodically merge/streamline internal and external data file transfer services to eliminate waste; And (4) merging/streamlining the Company data file transfer services reduces cyber attack vectors and creates a better, 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; And (2) enabling and testing in scope file transfer processes.

- **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

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transactions--the risk associated with problems stemming from an outdated and unsupported version is too high. (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 SaaS 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 best, most cost-effective alternative, balancing costs, known risks, and even growing business capacity and productivity.

- The **Critical Substation Upgrade** project requires \$3,498,167 in capital (\$3,135,966 ROM Adjusted Capital) and \$396,667 in O&M in the test year.
 - **Description:** This project will implement enhanced security measures at the Company's most critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time. With the enhanced security posture, Consumers Energy will be better positioned to mitigate malicious activity and increase the reliability of electric delivery to customers.
 - **Problem Statement:** Today, Consumers Energy currently deems 16 substations as business critical to its electric system while an additional 34 substations fall under NERC-CIP compliance. Recent attacks to critical infrastructure have increased the likelihood of an adversary exploiting vulnerabilities at critical substations, increasing the risk for large scale outages and customer impact. The Company's current security measures do not allow it to detect, deter, or monitor potential threats on site. Without the ability to monitor these assets in real-time, the Company is vulnerable to an adversary causing destruction without knowledge of when or how the event took place. A phased implementation would allow the Company to systematically mitigate risk to assets deemed most vulnerable.
 - **Objectives:** The objective of this project is to implement enhanced security measures to better detect, deter, and respond to threats to the Company's electric substations in real-time. This enhanced security posture will align with other utilities that own and operate substations and mitigate disruption to electric service while improving reliability.
 - **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) fence intrusion (which will be accomplished through camera systems); (6) subcontractor work of trenching poles, installing equipment, etc.; (7) additional facility lighting; and (8) security equipment maintenance. These activities will be performed

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at the following company locations: Acme (Acme), Algoma (Sparta), Alma (Alma), Amber (Ludington), Barry (Hastings), Beals Road (Wyoming), Beecher (Adrian), Beveridge (Flint), Blackstone (Jackson), Boardman (Traverse City), Brickyard (Holton), Broadmoor (Grand Rapids), Campbell (West Olive), Cannon (Rockford), Cement City (Cement City), Churchill (Leslie), Clearwater (Kalkaska), Cleveland (Spring Lake), Cole Creek (Flushing), Crescent (Hillsdale), Croton Dam (Newaygo), David (Pewamo), Deja (Edmore), Dort (Mt. Morris), Dowling (Hudson), Edenville Dam (Hope), Edwards (Kalamazoo), Ellsworth (Grand Rapids), Elm Street (Battle Creek), Eureka (Greenville), Farr Road (Onkama), Gleaner (Freeland), Gratiot Farms (Middleton), Grodi Road (Erie), Grout (Gladwin), Hazelwood (Plainwell), Hemphill (Flint), Hile Road (Muskegon), Hodenpyl Dam (Wexford), Holland Road (Saginaw), HSC Hemlock Semiconductor (Hemlock), Hughes Road (Marshall), Island Road (Charlotte), Jackson Plymouth (Jackson), Lafayette (Battle Creek), Layton (Chesaning), Lindbergh (Kalamazoo), Looking Glass (Lansing), Manlius (New Richmond), McNally (Charlevoix), Miles Road (East Jordan), Monitor (Bay City), Moore Road (Hillsdale), Morrow (Comstock), Muskegon Heights (Muskegon), Oceana (Hart), Ogemaw (West Branch), Page Avenue (Jackson), Pasadena (Flint), Pingree (Allendale), Raisin (Tecumseh), Rice Creek (Albion), Riverview (Kalamazoo), Silicon Hemlock Semiconductor (Hemlock), Simpson (Mendon), Sonoma (Battle Creek), Spartan (East Lansing), Thompson Road (Clarksville), Trowbridge (Allegan), Twining (Twining), Vernon (Clare), VeVay (Mason), Vrooman (Jackson), Washtenaw (Chelsea), Wealthy (Grand Rapids), and Willard (Birch Run).

- **Alternatives:** Alternatives considered include: (1) maintaining the current security perimeter fencing and conducting routine inspections of the sites. This alternative was not selected, as it does not provide the ability to prevent, detect, or respond to threats in real-time. (2) The best option is implementing enhanced security measures at the most critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time.
- The **HR Support Pack and Business Software Inc (“BSI”) Upgrade 2026 and 2027** projects require the following O&M in the test year.

Project Year	Test Year O&M
2026	\$246,223
2027	\$123,112

- **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.

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- **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:** Alternatives considered include: (1) not upgrading to the current support packs, which results in noncompliance with financial rules and regulations and inaccurate payroll.(2) there is no economical cloud solution, so this option was not entertained(3) the Company decided the best alternative is to apply the appropriate support pack upgrades. This option is preferred because it enables the Company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.
- The High Voltage Distribution (“HVD”) SCADA Upgrade project requires \$335,461 in capital (\$268,369 ROM Adjusted Capital) and \$163,773 in O&M in the test year.
 - **Description:** The Electric HVD Monitoring System Upgrade project upgrades the software and hardware components of the HVD SCADA system. This system is used to monitor and control generation, transmission, and HVD voltage circuits. The upgrade will provide new functionality and enable new capabilities.
 - **Problem Statement:** Running on an older version of the HVD Software could have potential impacts on the reliability and resiliency of the low voltage distribution (“LVD”) system as well as the HVD system, as distribution reliability metrics depend upon HVD system availability. Maintaining an older version of the software and hardware creates risks associated with vendor responsiveness in addressing problems, as they arise. It will also take more effort to support any upgrades in the future because of difficulties resulting from longer durations between upgrade efforts. If upgrades are delayed, additional full-time resources will be required for the year upgrades occur to address upgrade complexities.
 - **Objectives:** Upgrading the HVD SCADA software and hardware adds value to the Company by ensuring that problems are promptly addressed when they occur. Additionally, the upgrade includes enhancements and fixes to the core product that support the resiliency of electric delivery, ensuring that customers are receiving the energy they need when they need it. Also, the distribution system depends on availability of the HVD system

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as staying current with the solution provider upgrades is critical to the resiliency of both systems.

- **Scope:** The scope of this project is an upgrade to the HVD SCADA software and hardware, which encompasses the following: (1) upgrading the application software; (2) upgrading the underlying application hardware; (3) implementing new functionality for improved value to the Company; (4) making necessary configuration changes; and (5) updating documentation related to the integration changes.
- **Alternatives:** Alternative considered include: (1) deferring the biennial upgrade of the SCADA application and its hardware. The Company targets SCADA biennial application upgrades to stay within two versions of the current application state to maintain application stability and cyber security, given the critical nature of the SCADA system. This alternative was not chosen due to increased security risk and the need for vendor support of the application. Additionally, the hardware is already past the end of its useful life and has been moved over to a third-party warranty provider. (2) alternative vendor solution. This option was not chosen because the move from our current vendor would be time consuming and costly. It could also introduce instability as any alternative solutions have not been proven operationally; 3) doing nothing. This option was not chosen due to the critical nature of these systems and the potential operational risks associated with operating on an unsupported solution. (4) The option chosen is to complete the upgrade with associated hardware and software necessary to complete the project that will deliver new functionality for improved value.
- The **Itron Enterprise Edition (“IEE”) 2025 Upgrade** project requires \$50,812 in O&M in the test year.
 - **Description:** This project will upgrade IEE, which collects the reads from meters to ensure non-estimated bill accuracy.
 - **Problem Statement:** IEE is the Company’s keystone application of the Advanced Metering Infrastructure (“AMI”), that provides billing data that includes time of use data. If this application does not stay current, the Company increases the risk business operations could be interrupted or compromised. IEE is a key component in keeping the Company current, with billing capacity, stability, and accuracy obligations.
 - **Objectives:** This project creates value for the Company by: (1) ensuring the features and functionality needed to meet and exceed customer satisfaction and billing accuracy are available to business partners and IT; and (2) meeting Information Security’s requirement to keep applications patched and protected from cyber attack.

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- **Scope:** The scope of this project includes: (1) upgrading the IEE applications to the next appropriate versions; and (2) migrating the database to the next version required by the application.
- **Alternatives:** Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because it would decouple Itron IEE (Consumers Energy's Meter Data Management ("MDM")) from the Itron security infrastructure introducing application instability, security, and dependency risks to the utility, possibly negatively impacting critical customer electric and gas billing operations. It would also likely affect other business critical Itron applications, creating more expense to support and no ability to leverage updated tool capability. (2) replacing 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 initial multi-million dollar project. (3) performing the upgrade is the best alternative. This option is superior for both customers and the Company because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Itron products.
- The **Itron Enterprise Edition 2027 Upgrade** project requires \$83,541 in capital (\$66,833 ROM Adjusted Capital) and \$102,784 in O&M in the test year.
 - **Description:** This project will upgrade IEE, which collects the reads from meters to ensure non-estimated bill accuracy.
 - **Problem Statement:** IEE is the Company's keystone application of AMI, that provides billing data that includes time of use data. If this application does not stay current, the Company increases the risk business operations could be interrupted or compromised. IEE is a key component in keeping the Company current, with billing capacity, stability, and accuracy obligations.
 - **Objectives:** This project creates value for the Company by: (1) ensuring the features and functionality needed to meet and exceed customer satisfaction and billing accuracy are available to business partners and IT; (2) meeting Information Security's requirement to keep applications patched and protected from cyber attack.
 - **Scope:** The scope of this project includes: (1) upgrading the IEE applications to the next appropriate versions; (2) migrating the database to the next version required by the application; and (3) replacing hardware required by the next version to maintain operating system currency.
 - **Alternatives:** Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because it would decouple Itron IEE (Consumers Energy's MDM) from the Itron security infrastructure introducing application instability, security and dependency risks to the

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utility, possibly negatively impacting critical customer electric and gas billing operations. It would also likely affect other business critical Itron applications, creating more expense to support and no ability to leverage updated tool capability. (2) replacing 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 initial multi-million dollar project.(3) performing the upgrade is the best alternative. This option is superior for both customers and the Company because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Itron products.

- The **ISIS Papyrus 2026 Upgrade** project requires \$328,999 in capital (\$263,199 ROM Adjusted Capital) and \$114,044 in O&M in the test year.
 - **Description:** This project will upgrade the Papyrus Objects suite of applications to the most recent version available per vendor recommendation. The ISIS Papyrus application is critical to creating electronic and paper correspondence for customers, including bills and dunnings.
 - **Problem Statement:** The application will be at least 1 major upgrade revision behind by 2026. It's imperative that customers retain unfettered access to their paper bills, dunning notices, and other communications produced by ISIS. ISIS also makes customer bills available for online viewing through the website and mobile apps. Without the upgrade, vendors make no guarantee that any substantial patches or hot fixes impacting application reliability, capacity, and security will be forthcoming. The upgrade will address these problems and challenges, as well as ensuring all other platform components comply with the Company's operational and security standards.
 - **Objectives:** The value of this project includes: (1) providing a more stable operational model by upgrading to the most recent version available; (2) maintaining the necessary vendor support; and (3) resolving tuning and stability issues with the vendors.
 - **Scope:** The scope of the project is to upgrade the various licensed products that comprise the Papyrus Objects suite of applications.
 - **Alternatives:** Alternatives considered include: (1) delaying the upgrade and continuing to operate with the current version. This alternative was not chosen due to the risk of application stability and the inability to maintain cyber security patching. (2) The Company instead decided to upgrade to the current version. This alternative was chosen as it eliminates the risk of application instability and the inability to maintain cyber security patching.

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- 1 • The **Rate Change Maintenance** project requires \$184,667 in O&M in the test
2 year.
 - 3 ○ **Description:** The Rates Change Maintenance project will modify SAP
4 billing in accordance with pricing and rate change requirements.
 - 5 ○ **Problem Statement:** For the Company to continue to meet and comply
6 with certain MPSC requirements and to enable it to update its rates when
7 rate changes are approved, there is a need to make periodic
8 updates/modifications to existing prices and rate structures. These updates
9 help ensure accuracy of billing and provide optimal rates for customers.
 - 10 ○ **Objectives:** The project will add value for both the Company and its
11 customers through: (1) improved customer satisfaction by providing
12 accurate billing; (2) optimized rate configuration enabling rate changes to
13 be made more efficiently; and (3) timely updates to Company applications
14 that incorporate mandatory changes to the rate structure that include new
15 surcharges, price changes, and energy efficiency programs.
 - 16 ○ **Scope:** The scope of this project encompasses (1) implementation of annual
17 or monthly (or both) electric and gas customer price changes, and rate
18 structure changes as approved by the MSPC; and (2) optimizing the rate
19 configuration in the Company's back-end system for more efficient rate
20 changes.
 - 21 ○ **Alternatives:** Alternatives considered include: (1) a fully dedicated
22 offshore development model. The option ensured resources were readily
23 available with a more cost-effective labor expense. This alternative was not
24 chosen due to the risk of billing inaccuracies and customer complaints.
25 These risks were deemed too high because of the complexities of the rate
26 structure, new development, and the time it would take for testing of this
27 model; and (2) Instead, the Company chose to leverage onshore resources
28 to plan, coordinate, and execute the rate changes. This option was selected
29 as it supports the Company's operation model for rate changes.
- 30 • The **SAP Support Pack Upgrade 2026** project requires \$410,658 in O&M in
31 the test year.
 - 32 ○ **Description:** The SAP Support Pack Upgrade project is to maintain the
33 currency levels of all SAP applications. This will ensure the applications
34 are at version levels that are supported by SAP, have the latest patches and
35 bug fixes, and provide cross-application compatibility for business partners.
 - 36 ○ **Problem Statement:** To continue to maintain SAP application version
37 currency, across all applications, the support packs released by SAP must
38 be routinely applied. Without maintaining application currency, the core
39 business applications running on the SAP platform are at risk of losing

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1 vendor support, resulting in the inability to apply bug fixes and patches,
2 including security patches, and maintain application interoperability and
3 stability.

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

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

- 16 ○ **Alternatives:** Alternatives considered include: (1) dividing the scope into
17 individual projects by SAP application. This alternative was not selected
18 because the efforts are interrelated and completing them separately could
19 lead to duplication of work, especially testing efforts, and therefore
20 potentially higher costs. (2) migrating to SAP S/4HANA. This option was
21 not selected because SAP S/4HANA is a multi-year project that is not
22 expected to be completed by year-end 2026. So an alternative approach is
23 needed to perform the application upgrades and maintain currency in the
24 meantime. (3) Ultimately, the Company chose to balance the project scope
25 through regular support pack upgrades. This alternative was selected
26 because it provides the best balance of minimizing cost and maintaining
27 support by combining multiple application upgrades through a single
28 support pack upgrade effort.

- 29 • The **SiteCore Secondary Upgrade 2027** project requires \$20,308 in O&M in
30 the test year.

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

- 36 ○ **Problem Statement:** Sitecore requires regular upgrades to adhere to the
37 vendor’s support lifecycle to ensure system reliability, take advantage of
38 new application features, maintain current security updates, and improve
39 the customer’s website experience.

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- **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 (Customer Experience Index) goals by improving reliability and performance.
- **Scope:** The project scope is to upgrade the Sitecore content management software to the latest available version.
- **Alternatives:** Alternatives considered include: (1) Delay the upgrade. This alternative was not chosen due to the need to prevent the application from 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) Migrating to a cloud solution was also considered. This alternative was not chosen due to the cost/benefit analysis of re-architecting the Company's current Sitecore implementation to facilitate cloud migration that is not viable at this time; and (3) Rejecting these alternatives, the Company chose to upgrade Sitecore on a two-year cycle because it provides up-to-date functionality, stability, and mitigates cyber security risks while minimizing cost and impact.

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

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

- Column (a) provides the application name;
- Column (b) provides a disaster recovery tier, where applicable;
- Column (c) provides total projected 2026 capital expenditures;
- Column (d) provides total projected 2026 O&M expense;
- Column (e) provides total projected 2027 capital expenditures;
- Column (f) provides total projected 2027 O&M expense;
- Column (g) provides total test year capital expenditures;

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- Column (h) provides total test year O&M expense;
- Column (i) provides the electric allocation for test year capital expenditures; and
- Column (j) provides the electric 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.

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

2 **A.** The following describes the Application Currency projects:

- 3 • **The Application Currency - Capital and Application Currency - O&M:**
 - 4 ○ **Description:** These initiatives will utilize capital and O&M funding to keep
5 applications current for security and reliability. O&M is included with
6 capital projects to complete expense activities associated with capital
7 upgrades.
 - 8 ○ **Problem Statement:** The Company manages a large number of
9 applications in the technology landscape that require regular version
10 upgrades to maintain vendor-supported software versions. Without vendor
11 supported versions, the Company loses the ability to receive version updates
12 and upgrades to address defects, patch security vulnerabilities, protect
13 against cyberthreats, protect data, and add new features. Failure to upgrade
14 these applications can have a direct negative impact on key customer and
15 business processes, increase support costs, increase unplanned outages, and
16 increase cyber security vulnerabilities.
 - 17 ○ **Objectives:** Maintaining the appropriate versions of applications through
18 application currency upgrades adds value by: (1) enabling the Company to
19 maintain vendor support; (2) remediating vendor security vulnerabilities
20 and enhancing security protections; (3) addressing vendor defects that
21 impair stability and functionality, leading to fewer incidents due to outdated
22 software; and (4) addressing version interdependencies and compatibility
23 between systems. This is essential to delivering safe, reliable, and
24 affordable service to the Company's customers. The application upgrades
25 in scope are regularly prioritized based on considerations that include
26 application criticality; number of versions behind the current available
27 version; security and operational risk; operational impacts of performing the
28 upgrade; ability to defer; and cost.
 - 29 ○ **Scope:** The scope of upgrading these applications encompasses:
30 (1) upgrading the application software; (2) assessing any new functionality
31 for value to the Company; (3) making necessary configuration changes;
32 (4) testing the upgraded software; and (5) updating documentation related
33 to the integration changes.
 - 34 ○ **Alternatives:** Applications are routinely evaluated to determine if and what
35 upgrade efforts are necessary to maintain an appropriate level of currency,
36 as well as the priority of those efforts. During that review, the alternative
37 of delaying the timing of the individual upgrades is considered based on:
38 (1) maintaining an optimal balance between keeping the application current
39 and risking failure; (2) an increased number of incidents; (3) paying
40 increased support costs; and (4) preventing employees from performing

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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 spending 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	\$62,876	\$50,301	\$5,306
Application Currency-Corporate-O&M	\$0	\$0	\$180,634
Application Currency-Customer-O&M	\$0	\$0	\$69,663
Application Currency-Electric & Gas Shared-Capital	\$48,975	\$39,180	\$217,312
Application Currency-Electric & Gas Shared-O&M	\$0	\$0	\$317,806
Application Currency-Electric-O&M	\$0	\$0	\$287,098
Application Currency-IT/Digital Foundation-Application Platforms-Capital	\$97,409	\$77,927	\$97,268
Application Currency-IT/Digital Foundation-Application Platforms-O&M	\$0	\$0	\$156,695
Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M	\$0	\$0	\$22,229
Application Currency-Operational Technology-Capital	\$80,841	\$64,673	\$22,920
Application Currency-Operational Technology-O&M	\$0	\$0	\$187,262
Application Currency-Security-Capital	\$73,370	\$58,696	\$6,632
Application Currency-Security-O&M	\$0	\$0	\$209,175

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 2020 through 2027. Specifically:

- Column (a) provides the year reference;
- Column (b) identifies the electric 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 electric 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.

In further detail, by category, the Total Electric Projected and Actual/Projected Spend amounts are derived from Exhibit A-24 (SHB-9), page 1, which are the source for the figures indicated. The Total Company Incremental Annual Worklist, which is broken out in Exhibit A-25 (SHB-10), is defined as the total Company cost of planned enhancement requests received in the year indicated in Exhibit A-24 (SHB-9), page 2. The Total Electric

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Allocation Incremental Annual Worklist provides the electric allocation of the total Company incremental worklist. The Total Electric Annual Demand is defined as the total fulfilled and unfulfilled enhancement demand for the year, calculated by the sum of Total Electric Actual/Projected spend and Total Electric Allocation Incremental Annual Worklist. Total Company Cumulative Worklist is defined as the year-over-year increase of unfulfilled enhancement requests. Total Electric Allocation Cumulative Worklist provides the electric allocation of the Total Company Cumulative Worklist.

Q. What is the purpose of Enhancements investments?

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

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

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

- Column (a) provides the Enhancement open date, internally referred to as the Open Date of the request;
- Column (b) identifies the Number, which is used to internally track the lifecycle of the Enhancement request;
- Column (c) identifies the Type of request;
- Column (d) provides a Description of Work;

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

Q. How does the Company track and manage enhancements?

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

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

A. The demand for enhancement efforts has grown an average of 49% over the past three years because of the increased need for automation efforts, focus on waste elimination and cost optimization, additional functionality requests to optimize aging applications, and enhanced functionality requests for newly implemented technology.

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As of October 2024, the Company has a worklist (Exhibit A-25 (SHB-10)) of 639 Company-wide requests to improve multiple applications and systems. This well-known worklist demonstrates the high volume of demand for smaller technology efforts. Despite exceeding the projected spend in several previous years, the Company is unable to keep up with the growing demand for enhancements, as shown on Exhibit A-24 (SHB-9), page 2. The projected Total Electric Allocation Cumulative Worklist (Demand) for the test year is \$17,999,226 (Exhibit A-24 (SHB-9), page 2, line 7, column j), while the Company is projecting \$10,120,181 of Total Electric 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 2026 and 2027 based on a known worklist, plus applying a combination of historical demand and historical spend. The projected level of demand still outpaces projected spend, as indicated above.

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

A. The Company is using two methods to validate enhancement demand expenditures and expenses in the test year: (1) three-year historical average and (2) total cumulative demand. For the three-year historical average method, the Company calculated the actual three-year historical average for 2022-2024 of \$9,564,426 plus known incremental work of \$6,801,862 (\$16,366,289) and compared it to the projected Test Year enhancement expenditures and expenses of \$10,120,181. This validates Test Year projections are in line with historical spending and known incremental work. Then for the total cumulative demand method, the Company compared the Total Electric Allocation Cumulative

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Worklist amount of \$17,999,226, in Exhibit A-24 (SHB-9), page 2, line 7, column j, to the projected Test Year enhancement expenditures and expenses of \$10,120,181. This comparison validates these projections are in line with the projected demand.

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

A. Projections for the total cumulative worklist in 2026 and 2027 are based on the three-year average annual increase to enhancement demand. As indicated, cumulative enhancement requests grew at an average annual rate of 17% 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, line 7. Validating the projected Enhancement spending based on a known worklist and a three-year historical average of actual spend is an indication that the Company's test year projected spend of \$10,120,181 is reasonable and prudent.

Q. Please explain the Enhancements projects.

A. The following are the Enhancements projects:

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

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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 spending requirements for each Enhancement project are indicated in the table below.

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Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	Test Year O&M
Energy Assistance Enhancements and Maintenance Annual Updates	\$0	\$0	\$193,086
Product Family Enhancements-Corporate-Capital	\$1,454,687	\$0	\$193,040
Product Family Enhancements-Corporate-O&M	\$0	\$0	\$116,530
Product Family Enhancements-Customer-Capital	\$2,365,309	\$0	\$107,817
Product Family Enhancements-Customer-O&M	\$0	\$0	\$172,976
Product Family Enhancements-Electric & Gas Shared-Capital	\$710,841	\$0	\$96,252
Product Family Enhancements-Electric & Gas Shared-O&M	\$0	\$0	\$124,350
Product Family Enhancements-Electric-Capital	\$1,597,161	\$0	\$242,126
Product Family Enhancements-Electric-O&M	\$0	\$0	\$240,811
Product Family Enhancements-Application Platform Services-Capital	\$502,706	\$0	\$102,957
Product Family Enhancements- Application Platform Services -O&M	\$0	\$0	\$103,502
Product Family Enhancements-Infrastructure Platform Services-Capital	\$432,985	\$0	\$261,025
Product Family Enhancements-Infrastructure Platform Services-O&M	\$0	\$0	\$144,327
Enhancements-Security-Capital	\$559,651	\$0	\$94,628
Enhancements-Security-O&M	\$0	\$0	\$303,412

Digital Foundations and Capabilities Projects

Q. Please explain the Digital Foundations and Capabilities projects.

A. Below are the Digital Foundations and Capabilities projects:

- The **Data & Analytics Platform Rationalization** project requires \$3,140,597 in capital (\$2,512,478 ROM Adjusted Capital) and \$538,611 in O&M in the test year.
 - **Description:** This project will optimize the Data & Analytics system landscape by creating connections, migrating data into Data Lake 2.0 (“DL 2.0”), and building visualizations from the data in DL 2.0. Following the enablement of DL 2.0, retirement of the IT Data & Analytics legacy systems

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including SingleStore Data Lake (“SSDL”), SAP BW, SAP BOBJ, Native HANA, the BW Portal, and SAP BODS creates value by reducing the total cost of ownership associated with maintaining and supporting legacy systems.

- **Problem Statement:** The IT Data & Analytics legacy systems (SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS) are outdated, inefficient, and becoming duplicative in nature with the introduction of DL 2.0. If these legacy systems are not retired, they will continue to cost the Company money as major investments are needed to maintain and support them.
- **Objectives:** This platform rationalization project creates value for the Company and its customers by reducing the total cost of ownership associated with maintaining and supporting legacy systems including licensing fees, maintenance costs, infrastructure, and support resources.
- **Scope:** The project scope includes: (1) the assessment of the existing Data & Analytics platforms including SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS; (2) inventory of data and reports still being used by stakeholders; (3) determination of migration strategy; (4) data migration to the Azure Data Lake; (5) report migration to Power BI; (6) organization change management; and (7) the retirement/decommissioning of the legacy platforms and applications.
- **Alternatives:** Alternatives considered: (1) upgrade legacy systems in place (on-premise). This alternative was not selected because this is costly and misaligned with the Company’s cloud strategy; (2) Lift and shift these on-premise systems to the cloud through the Hybrid Cloud Transformation Program. This alternative was not selected because it would duplicate the work being done as part of the DL 2.0 project and would not provide the same efficiencies that DL 2.0 introduces; (3) Migrate all data sources to DL 2.0 and retire legacy systems. This alternative was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.
- The **Digital-Infrastructure Automation** project requires \$477,554 in capital (\$382,043 ROM Adjusted Capital) and \$159,902 in O&M in the test year.
 - **Description:** This project will automate the deployment, maintenance, and tear down or decommissioning of cloud and data center services, leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services while reducing operational costs.

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- 1 ○ **Problem Statement:** As the Company uses cloud services to provide
2 infrastructure for applications, the difficulty of manually deploying,
3 maintaining, and decommissioning infrastructure, improving efficiency of
4 the use of infrastructure, bolstering resiliency, maintaining security posture,
5 and extending new capabilities increases significantly. The manual
6 approach lengthens application implementation times and leads to
7 inconsistent and/or incorrect deployment of infrastructure.
- 8 ○ **Objectives:** This project will create value by ensuring the Company's
9 application infrastructure requirements are met through automation.
10 Specifically, the project will create automation to deploy, maintain, and
11 deprovision infrastructure in a modular fashion to be used by product teams
12 to deploy, maintain, upgrade, and deprovision Company applications.
13 Thus, the project will: (1) improve the efficiency of the use of infrastructure
14 by allowing for infrastructure to be provisioned when needed, and
15 deprovisioned when not needed; (2) bolster the resiliency of infrastructure
16 by creating reusable resilient patterns and scalability for applications to use;
17 (3) deploying and removing infrastructure securely; and (4) enhancing or
18 extending automation for new cloud and data center services to support
19 Company applications.
- 20 ○ **Scope:** The project scope includes: (1) procuring automation software;
21 (2) building automation for cloud and data center services; (3) building
22 resiliency and scalability into the services; (4) building security posture into
23 the services; and (5) enhancing existing or extending automation for new
24 services.
- 25 ○ **Alternatives:** Alternatives considered included: (1) manually deploying,
26 maintaining, and decommissioning infrastructure to support Company
27 applications. This alternative was not chosen because it has proven to be
28 slow, costly, and error-prone; (2) manually improving the efficiency in the
29 use of infrastructure. This alternative was not chosen because the Company
30 does not have the necessary people to manually do this work at the scale
31 necessary to support the Company's portfolio of applications; (3) manually
32 bolstering resiliency. This alternative was not chosen because it has proven
33 to be error-prone; (4) manually maintaining security posture. This
34 alternative was not chosen because the Company does not have the
35 necessary people to manually do this work at the scale necessary to support
36 the Company's portfolio of applications; (5) manually extending new cloud
37 services. This alternative was not chosen because the services become
38 available faster than the Company can manually deploy them while meeting
39 necessary standards and security postures; (6) and utilizing pre-built tooling
40 without extension or development. This alternative was not chosen because
41 pre-built tooling does not meet the necessary Company standards and
42 security postures; (7) procure automation software and extend the software
43 to meet Company standards. This alternative was selected because the
44 combination provides the most cost-effective method for automation of

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existing and new services at speed and scale while allowing the services to be deployed in a secure manner that meets Company standards.

- The **OT Datacenter Migration** project requires \$3,343,208 in capital (\$2,674,566 ROM Adjusted Capital) and \$570,345 in O&M in the test year.
 - **Description:** The OT environment consists of systems supporting the control and monitoring of electric grid, electric generation, gas compression, and natural gas pipeline. These systems are critical for safe and reliable natural gas and electric delivery. The OT Datacenter Migration project enhances the Company's capabilities by co-locating to an enhanced datacenter at a vendor facility.
 - **Problem Statement:** The Company's current datacenter for the OT environment needs modernization and relocation from the Parnall Data Center. The current location is not the preferred location to house servers and systems critical to the control of the Electric Grid or Gas Pipeline due to the close proximity to a railway system. The climate conditioners in the current OT datacenter are aging and have had faults resulting in unplanned shutdowns . The location of the datacenter in the basement of the Parnall building is nearby to the main water piping for the building. There have been instances of water infiltration in the past.
 - **Objectives:** This project creates value for the Company by significantly strengthening capabilities through: (1) mitigating legacy physical and location risks at the current Parnall site; (2) migrating the OT infrastructure to a modern, highly secured environment with redundancy in climate conditions; and (3) better datacenter facilities support with a guarantee of redundant power.
 - **Scope:** The scope of the project includes: (1) migration of the OT environment from the Parnall Data Center to a co-located vendor data center; (2) re-validation of the OT Production and Disaster Recovery procedures once migration is completed; (3) migration of IT systems required for supporting the OT environment; and (4) decommission the existing OT environment from the Parnall location.
 - **Alternatives:** The Company performed an analysis of alternatives to expand capabilities as well as address constraints and risks: (1) Remain at the current Parnall Data Center; (2) migrate OT environments to the Cloud; and (3) relocate to a third-party co-location facility. Current industry best practices do not recommend migration of OT environments to the cloud. The co-location vendor provides the building, cooling, power, and physical security the Company lacks for its servers, storage, and other computing and networking equipment at the current Parnall location. Based on the analysis, the Company decided to implement the third alternative.

1 **Q. Please explain the SAP HANA Database Migration project.**

2 **A.** The SAP HANA Database Migration project has the following synopsis:

- 3 ○ **Description:** In preparation for SAP's planned end of support for its
4 Business Suite product in 2027, the Company will migrate its existing SAP
5 databases from Oracle to SAP HANA in advance of the required move to
6 S/4HANA.
- 7 ○ **Problem Statement:** The Company's SAP applications currently utilize
8 Oracle's relational database management system as their underlying
9 database storage technology. SAP has informed its customers that standard
10 support for its legacy Business Suite (aka ECC) product will end in 2027,
11 along with support for all non-SAP database platforms. SAP has also
12 informed customers that the future direction for their enterprise solution is
13 S/4HANA, a solution built explicitly for their HANA database platform. To
14 prepare for these upcoming events, the Company will migrate all of its SAP
15 databases off of Oracle and onto SAP HANA.
- 16 ○ **Objectives:** This project lays the groundwork for the Company's eventual
17 shift to SAP's HANA-based solutions by: (1) proactively migrating SAP
18 databases to a database technology that is fully supported by SAP beyond
19 2027; and (2) mitigating the risk of a complete loss of support for the current
20 Oracle database technology in 2027.
- 21 ○ **Scope:** Project scope includes: (1) procurement of HANA software
22 licensing to cover all migrated SAP applications; (2) data migration for all
23 SAP applications from the Oracle database to SAP HANA; and
24 (3) implementation of new application support policies, procedures, and
25 tools required to manage the newly migrated SAP HANA applications.
- 26 ○ **Alternatives:** Given SAP's announcement regarding the end of support for
27 its ECC product in 2027, all customers running SAP on database software
28 other than HANA will also lose support for their associated database
29 software in 2027. SAP is offering no other options for databases other than
30 HANA beyond 2027. While there is no alternative to the HANA database
31 for SAP going forward, the Company has considered multiple options:
32 (1) Perform a direct migration from SAP Business Suite on Oracle to
33 S/4HANA. A direct migration to S/4HANA brings greater operational risk
34 to the Company as both the underlying database technology and the SAP
35 application's functionality would change simultaneously, so this alternative
36 was not selected; (2) Remain on the current SAP Business Suite product but
37 competitively bid support services to a third-party provider instead of SAP.
38 This alternative was not selected because moving to a third-party support
39 model forces the Company to remain on outdated SAP software and
40 eliminates any possibility of benefitting from new business functionality
41 provided by S/4HANA. It will also require the Company to accept

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significant risk due to the fact that SAP security patches, application patches and upgrades will not be available upon termination of the SAP maintenance agreement; (3) Migrate to SAP's SaaS implementation of S/4HANA. This alternative was not selected because an S/4HANA SaaS migration is a much more disruptive option as the Company's business processes must be adjusted to accommodate functionality differences between ECC and S/4HANA. The risk of negative business impact is significantly greater than simply changing the underlying database technology. The selected alternative to migrate the SAP databases to HANA prior to implementing S/4HANA gives the Company several years to solidify its HANA database infrastructure before introducing the substantial business process changes required with S/4HANA.

Q. What is the Company's migration timeline for the SAP HANA Database Migration project?

A. The Company initiated the SAP HANA Database Migration project in April 2023 and is anticipated to be completed by December 2025. The migration will be staggered across 2024 and 2025. In 2024, the Company migrated ancillary systems to HANA to gain valuable insight from these migrations and address any technical issues before migrating the ECC in 2025. This will also provide time to conduct mock migrations for ECC, which will help minimize downtime.

Q. Please explain the SAP S/4HANA Implementation project.

A. The SAP S/4HANA Implementation project has the following synopsis:

- The **SAP S/4HANA Implementation** project requires [REDACTED] in capital ([REDACTED] ROM Adjusted Capital) and [REDACTED] in O&M in the test year.
 - **Description:** This project will modernize the Company's current SAP ERP solution. Upon completion, the solution will provide enhanced functionality across several business areas while providing a supported and secure platform capable of business transformation.
 - **Problem Statement:** The current SAP ERP system will reach the end of mainstream vendor maintenance on December 31, 2027. Operating the system beyond the end of support date creates significant risks to comply with regulatory mandates, perform core customer supporting business operations, and apply the latest security patches that are critical for cyber

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protection against customer and employee data breaches. In addition, an unsupported platform limits improvement of operational efficiency and maintaining the stability, reliability, and security of the system.

- **Objectives:** The S/4HANA program will position the Company for business transformation by enabling it to (1) provide and maintain capabilities for protection of sensitive customer and employee data; (2) provide enhanced system stability and reliability needed in a 24x7 business by significantly reducing system maintenance outages; (3) mitigate the regulatory and operational risks of running critical business processes on an unsupported platform; (4) implement simplified workflows and standardized processes by reducing customizations; and (5) use in-memory computing with embedded real-time analytics to make smarter, faster decisions.

- **Scope:** The project scope includes (1) Migrating the current SAP ERP solution to the latest S/4HANA solution. This includes (a) moving to the latest version of the software, (b) migrating existing data to the new S/4HANA data model, (c) connecting interfaces from other systems into S/4HANA, (d) using newer user interfaces available in S/4HANA where feasible, (e) setting up users and user access in the new system, (f) migrating existing reports and analytics or replacing them with new in-built reports and analytics in S/4HANA, and [REDACTED] (2) Enabling an architecture that minimizes downtime for system maintenance activities. (3) Implementing solutions where existing SAP ERP functionality is not available in S/4HANA. (4) Implementing a foundational “clean core framework.” This requires minimizing or remediating custom code and utilizing SAP customization best practices in the new version. These best practices will decouple the core SAP software from Company-specific customizations, hence making it “clean.” This clean core framework is expected to reduce the effort and cost of upgrading SAP in subsequent releases.

- **Alternatives:** An analysis was completed that included key industry input, feedback from business areas across the Company, technology leaders, and subject matter experts. This presented the organization with several alternatives, including the following: (1) Postpone the decision and stay on the current version. This would require purchasing the extended maintenance until 2030 due to the current mainstream maintenance expiring in December 2027. A skill shortage is anticipated as SAP customers scramble to meet the 2030 deadline. Delaying the Company’s decision to migrate to S/4HANA would put the Company at a higher risk of securing those high-demand skilled resources. Staying on the current version beyond 2030 with third-party support would limit the Company’s ability to continuously improve operational efficiency and maintain the stability, reliability, and security of the system. This alternative was not selected

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1 because of the additional cost and risk, and the inability for the Company
2 and its customers to enjoy any added benefits or new application features;
3 (2) Eliminate SAP and use multiple best of breed solutions in the various
4 business areas. (3) Eliminate SAP and implement a new ERP solution. SAP
5 is currently used across the Corporate, Work and Asset Management, and
6 Customer areas. There are very limited options for a single ERP system that
7 provides all three areas of functionality. The current SAP system has over
8 100 satellite systems and around a thousand interfaces. Non-SAP
9 alternatives may not work with current satellite systems, requiring the
10 replacement or significant remediation of those satellite systems. These
11 non-SAP alternatives would require a much larger change management
12 initiative, significant reskilling of technical resources, and retraining of
13 people across the Company who have become familiar with SAP over the
14 last 16 years. Alternatives (2) and (3) are more expensive, complex to
15 implement and support long-term, therefore were not chosen; (4) Migrate
16 to the latest S/4HANA solution before the end of 2030. This option was
17 chosen because it mitigates risks and provides a supported and secure
18 platform capable of business transformation.

19 **Q. Describe the deployment approach the Company will utilize for the SAP S/4HANA**
20 **Implementation project.**

21 A. The Company will deploy the migration to the new S/4HANA solution in phases to reduce
22 the risk of operational impact to customers and co-workers. The Company will adopt
23 SAP's standard Activate methodology for the deployment approach.⁵ The Activate
24 methodology includes six phases: Discover, Prepare, Explore, Realize, Deploy, and
25 Run/Adopt. The Discover, Prepare, and Explore phases result in the design, which is then
26 built, tested, and deployed in the Realize, Deploy, and Run/Adopt phases. The approach is
27 to design the system holistically, meaning the Discover, Prepare, and Explore phases will
28 cover all modules of SAP, including Finance, Supply Chain, HR, Work Management, and
29 Customer. This ensures the system is designed optimally from end to end. Once the design

⁵ Available at <https://learning.sap.com/learning-journeys/discovering-sap-activate-implementation-tools-and-methodology/describing-sap-activate>

1 is complete, the Company will conduct multiple iterations of the Realize, Deploy, and Run
2 phases to deploy functional modules in a staggered capability deployment approach.

3 **Q. Please explain the different S/4HANA migration alternatives considered.**

4 A. The Company considered three migration alternatives: (1) Build a new SAP system without
5 using any existing customizations, configurations, processes, or data (Greenfield);
6 (2) Upgrade the existing SAP system, retaining existing customizations, processes, and
7 data, then remediate errors that arise in the upgrade process in a series of iterations
8 (Brownfield); and (3) Adopt a hybrid strategy, building a new SAP system, while
9 selectively migrating critical data and process from the existing system (Bluefield).

10 **Q. Which S/4HANA migration approach has the Company selected?**

11 A. The Company has selected the hybrid or Bluefield approach for the S/4HANA
12 Implementation project.

13 **Q. Why did the Company select the Hybrid, or Bluefield, migration approach for the**
14 **S/4HANA Implementation project and not the others?**

15 A. The Company chose the Hybrid, or Bluefield, approach because it offers the best balance
16 of lower risk and cost.⁶ While the Greenfield option provides lower total-cost-of-ownership
17 and faster time-to-value for implementations that want to shed a lot of legacy
18 customizations and start afresh, this is not fully the case for the Company because the
19 current system has many essential customizations in the customer billing and employee
20 payroll areas that will need to be rewritten in the new system with this approach. Rebuilding
21 customizations introduces significant risk and cost. Similarly, the Brownfield approach
22 could provide a shorter project timeline by migrating all the current customizations and

⁶ Available at <https://www.leanix.net/en/wiki/tech-transformation/s4hana-greenfield-vs-brownfield-approach>

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1 processes. However, this approach is not preferred in the Finance, Supply Chain, and Work
2 Management areas where the current system has a lot of custom processes, workflows,
3 enhancements, and interfaces that are suboptimal compared to the standard best practice
4 processes that come in S/4HANA. The Brownfield approach is also not preferred because
5 the processes and data model in Finance and Supply Chain have changed significantly.
6 Upgrading current customizations to the new system would not be easy and rewriting them
7 would be expensive and increase risk. This would result in a new system that does not
8 conform to SAP's clean core approach and would be expensive to upgrade in the future.
9 Therefore, the ideal approach is a combination of the two where the new system adopts a
10 Greenfield approach for Finance, Supply Chain and Work Management, and a
11 Brownfield-like approach for Customer and Payroll.

12 **Q. Why is the Company undertaking the expense and effort of migrating to the SAP**
13 **S/4HANA version at this time?**

14 A. Migrating to the SAP S/4HANA version is crucial for the Company because the
15 mainstream support for our current SAP version ends in December 2027. After evaluating
16 the project, the Company determined it will take approximately three years to complete.
17 Assuming the Company begins the project in 2025, the timeline will extend into 2028,
18 requiring the Company to purchase extended SAP support for 2028. It is important to note
19 that extended support for the Company's current SAP version is only available until 2030.

20 **Q. Will the Company's SAP systems face an increased risk of cyber-attacks if the**
21 **S/4HANA project is not executed?**

22 A. Yes. The Company's SAP systems will face increased risk of cyber-attacks if the
23 S/4HANA project is not executed, because SAP has stated that after maintenance ends,

1 standard patches will no longer be available for SAP customer-specific maintenance,
2 leaving the Company's SAP systems vulnerable to emerging threats from bad actors
3 exploiting known vulnerabilities.⁷

4 **Q. Please explain whether the Company's SAP systems will continue to operate if the**
5 **S/4HANA project is not executed?**

6 A. The Company's SAP systems will continue to operate with significant risk for an
7 indeterminate period of time if the S/4HANA project is not executed. SAP will not support
8 the Company's current SAP version after December 2027, when the mainstream
9 maintenance ends. After this period, the risk of operational disruptions will increase
10 significantly due to the lack of a Service Level Agreement with SAP, and there will be no
11 guarantee that SAP resolve any new issues that arise.

12 **Q. How did the Company develop the cost estimate for the SAP S/4HANA**
13 **Implementation project?**

14 A. The Company developed the cost estimate for the SAP S/4HANA Implementation project
15 with the support of an independent third party that specializes in preparing for S/4HANA
16 upgrades. The cost estimate consists of labor, contractor, software, and non-labor costs.

17 The labor and contractor cost estimates were derived as follows:

- 18 ○ First, the phases of the project were laid out in a timeline based on the
19 phased deployment approach and Hybrid migration approach, both
20 previously described in my testimony.
- 21 ○ Second, the high-level scope was identified, including the processes,
22 pain points, customizations, integrations, roles, and data volumes that
23 need to be migrated to S/4HANA.

⁷ Available at https://support.sap.com/en/my-support/knowledge-base/security-notes-news.html?anchorId=section_370125364.

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1 ○ Third, the effort for the design and subsequent phases were translated
2 into the number of hours and resources required for each phase. The
3 resources are further broken down into roles and number of each role.

4 ○ Lastly, the resource estimates were assumed to be a mix of 30% internal
5 employees and 70% external contractors. The Company then applied
6 an average resource rate based on internal and external resources to
7 calculate the cost estimate. For certain activities, the resource estimate
8 was derived using a percentage of the overall effort based on best
9 practices, e.g. program management and quality management.

10 • The software cost estimate was based on indicative Bill of Material (“BOM”)
11 from SAP.

12 • The non-labor cost estimates are based on business expense, and labor
13 overheads based on projected internal labor and external contractor costs to
14 support the project.

15 Finally, the Company conducted a comparison of peer utility overall cost estimates
16 and duration for their S/4HANA implementation projects to validate the Company’s
17 overall cost and duration estimate was reasonable.

18 **Q. Why is this SAP upgrade more costly than the Company’s previous upgrades?**

19 **A.** This SAP upgrade is more costly than the Company’s previous upgrades for several
20 reasons. First, the latest SAP S/4HANA version improves business processes, requiring
21 the Company to thoroughly evaluate these best practices against existing processes. This
22 evaluation is crucial in determining adoption and adds to the overall project cost.

23 Second, migrating data to the new system involves mapping, transforming, and
24 testing data elements required by S/4HANA’s new data model. Third, the Company must
25 re-evaluate and update user access because the system controlling access permissions has
26 changed in S/4HANA. Fourth, the existing solution has customizations that cannot be
27 moved to the new system as-is due to the differences in business processes, data model,
28 and permissions. Finally, SAP recommends customers adopt a “clean core” approach when
29 customizations are necessary. This approach moves the customizations outside the core

1 product, which makes future upgrades easier. This requires the Company to perform a
2 detailed evaluation and remediation of existing customizations.

3 **Q. Would it be more cost-effective for the Company to replace its SAP systems?**

4 A. No. It would not be more cost-effective for the Company to replace its SAP systems. This
5 would require re-engineering the entire SAP system to a new solution, assuming that the
6 current system could be replaced with a single replacement. It would require significant
7 effort to re-skill the Company's co-workers, re-engineer business processes, re-implement
8 the system, and integrate the new system with all the systems currently interfacing with
9 SAP. The Company currently has more than 1,000 interfaces to SAP. Replacing SAP with
10 multiple systems would be more costly and introduce additional risk due to the complexity
11 of managing multiple disparate solutions. The Company would need to develop
12 integrations between systems like Finance, Supply Chain, Work Management, and
13 Customer. These integrations are inherent in an integrated solution such as SAP.

14 **Q. Is the Company requesting any special rate-making treatment to amortize the cloud**
15 **implementation costs for the SaaS solutions that will be a part of the SAP S/4HANA**
16 **Implementation project?**

17 A. Yes. The Company is requesting to amortize the cloud implementation costs for the SaaS
18 solutions that will be a part of the SAP S/4HANA Implementation project over a 15-year
19 asset life. This software asset will provide significant value and functionality over an
20 extended period, as it is deeply integrated into the Company's business processes, and there
21 is a substantial investment in its development and integration. The benefits of continuing
22 to use the existing software outweigh the costs of transitioning to new software sooner than

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1 15 years. This approach will also benefit customers by spreading these costs over 15 years
2 to minimize the impact on customer rates.

3 **Q. Please describe Confidential Exhibit A-26 (SHB-11).**

4 A. Confidential Exhibit A-26 (SHB-11) is the IT S/4HANA Cloud Implementation Costs
5 balance for Electric and Common investments for the projected 13 months ending April 30,
6 2027. It provides a summary of the electric allocation of projected IT Department
7 investments expenditures. Specifically:

- 8 • Column (a) provides the balance category;
- 9 • Columns (b) through (n) provide each month's ending IT S/4HANA Cloud
10 Implementation Costs balance; and
- 11 • Column (o) provides the 13-month average of columns (b) through (n).

12 **Q. Please describe the purpose of Confidential Exhibit A-26 (SHB-11).**

13 A. The Company has identified cloud computing as a viable alternative for several technology
14 solutions associated with the SAP S/4HANA Implementation project. As discussed
15 previously, the Company is requesting to amortize the cloud implementation costs for the
16 SaaS solutions that will be a part of the SAP S/4HANA Implementation project over a
17 15-year asset life and adjusting working capital. Cloud implementation costs are projected
18 based on the planned implementations of the SaaS solution associated with the SAP
19 S/4HANA Implementation project. This working capital adjustment is provided by
20 Company witness Daly on Exhibit A-12 (PDD-34), Schedule B-4.

21 **Q. Is the Company requesting any additional special rate-making treatment for the SAP
22 S/4HANA Implementation project's IT Investments O&M expense?**

23 A. Yes. The Company is also requesting to defer the IT Investments O&M expense associated
24 with the SAP S/4HANA Implementation project and recover the expense over the life of

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the asset. This approach will benefit the customers by spreading these costs over the life of the asset to minimize the immediate impact on customer rates. This proposal will be discussed further in the direct testimony of Company witness Daly.

Q. Are there any Digital Foundations and Capabilities projects with disallowances from Case No. U-21585 that you would like to discuss?

A. Yes. The following Digital Foundations and Capabilities projects are addressed below.

- IT Operations Management - Service Operations;
- Operational Technology - Service Management Upgrade;
- Software Asset - Service Management Upgrade; and
- SolarWinds Performance Monitoring Expansion Upgrade.

Q. Please briefly describe the IT Operations Management - Service Operations project.

A. This project provides the Company access to a service mapping tool that leverages infrastructure data to identify all assets that support a service, with information about the service-specific relationship.

Q. Please briefly describe the Operational Technology - Service Management Upgrade project.

A. This project provides the Company service management capabilities for Operational Technology, to automate asset tracking, maintenance, and incident management for the operational technology assets.

Q. Please briefly describe the Software Asset - Service Management Upgrade project.

A. This project will give the Company automated monitoring, assessment, and oversight of software licenses and compliance to optimize software license management.

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1 **Q. Please briefly describe the SolarWinds Performance Monitoring Expansion Upgrade**
2 **project.**

3 A. This project provides the Company an IT observability and monitoring solution that
4 provides an aggregate view of IT system availability and performance.

5 **Q. What was the partial disallowance for the four Digital Foundations and Capabilities**
6 **projects discussed above in Case No. U-21585?**

7 A. The partial disallowance for the four Digital Foundations and Capabilities projects
8 discussed above in Case No. U-21585 was a 20% disallowance of the 2024 projected
9 amount (\$444,197) of \$88,839.

10 **Q. What was the Commission's reason for partial disallowance of the four Digital**
11 **Foundations and Capabilities projects 2024 projected amounts?**

12 A. The Commission's reason for partial disallowance of the four Digital Foundations and
13 Capabilities projects is the projects' 2024 projected cost estimates of \$444,197 was not
14 adequately supported.

15 **Q. Did Staff oppose the four Digital Foundations and Capabilities projects?**

16 A. No. Staff did not oppose the four Digital Foundations and Capabilities projects.

17 **Q. Is the Company requesting full recovery of the actual 2024 costs for the four Digital**
18 **Foundations and Capabilities projects in this case?**

19 A. Yes, the Company is requesting full recovery of the actual 2024 costs provided in the table
20 below for the four Digital Foundations and Capabilities projects in this case.

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Project	Capital 2024 Actuals	Confidential Exhibit A-20 (SHB-5) Reference
IT Operations Management – Service Operations	\$139,403	Line No. 73, column 1
Operational Technology – Service Management Upgrade	\$115,849	Line No. 75, column 1
Software Asset – Service Management Upgrade	\$49,003	Line No. 82, column 1
SolarWinds Performance Monitoring Expansion Upgrade	\$2,743	Line No. 84, column 1

Security Projects

Q. Please explain the Security projects.

A. Below are the Security projects:

- The **Business Continuity - Program Management Tool** project requires \$50,579 in O&M in the test year.
 - **Description:** The Business Continuity Program Management Tool is critical for successful and effective Business Continuity, Disaster Recovery, and Emergency Management Programs. The software tool will provide automation, enhance the Company's incident management processes, establish critical linkages between departments and essential functions they support, and will perform necessary analysis before, during, and after a disruption that allows for the efficient response to minimize downtime.
 - **Problem Statement:** The current business continuity and disaster recovery program management tool does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. The current tool limits automation opportunities and has gaps in how it handles template enhancements, which results in the need for manual workarounds in order to prevent losing critical data. The lack of capability affects reporting, upstream/downstream impact mapping, Incident Command System ("ICS") documentation automation, and user administration.
 - **Objectives:** This project will create value for the Company by: (1) maintaining the documentation that supports the recovery efforts of critical processes and associated essential functions that, if disrupted, would present significant impact to the Company and customers; (2) limiting business and community impact while providing a critical energy service; (3) prioritization of the recovery of critical processes and resource allocation during a business continuity incident(s); (4) providing a consistent, organized, and expedient response process (ICS) that is flexible to meet the needs of any incident, regardless of severity or scope; (5) providing a mechanism for identifying restoration gaps between critical

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business processes and IT recovery capabilities; (6) reducing or eliminating human error and waste; and (7) improved and more efficient user experience.

- **Scope:** The project scope includes: (1) framework for the development and maintenance of Business Continuity, System (Application) Recovery Plans, ICS, and Disaster Recovery Plans that are effective and easily accessible during an event; (2) automation for reporting to track status and to measure effectiveness and maturity of the program (Business Continuity, Emergency Management, Disaster Recovery Programs); (3) component for facilitating effective training exercises and response efforts through incident management tools that utilize concepts from the Federal Emergency Management Agency (“FEMA”) National Incident Management System (“NIMS”); (4) program management tools to monitor required program deliverables; (5) template for developing and maintaining site hazard assessments; (6) dependency mapping of critical business processes and IT applications; and (7) integrated business impact analysis process.
- **Alternatives:** Alternatives considered included: (1) continue to use Riskconnect (current Disaster Recovery tool). This alternative was not selected because it currently does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption; (2) Revert back to manual process. This alternative was not selected because the manual process is time consuming; and leads to human struggle and duplicative work. A previous KPMG Audit of the Business Continuity Program indicated the need for interdependency mapping and a software tool is the best way to accomplish this; (3) Implement a best-in-class SaaS solution to address the current incident management gaps and provide a consistent, organized, and expedient response process that supports the FEMA ICS. This alternative was selected because there are better SaaS solutions that fit the needs outlined above.
- The **Forward Web Proxy Services** project requires \$2,048,658 in capital (\$1,638,926 ROM Adjusted Capital) and \$201,735 in O&M in the test year.
 - **Description:** This project will replace the current web proxy service platform with a new platform. A web proxy service is a type of proxy server that sits between a client and the internet. It acts as an intermediary that evaluates, modifies, and forwards the client’s requests to the destination web server. This service offers many benefits for the Company such as advanced filtering. Advanced filtering in a forward web proxy service can filter out unwanted or harmful content from the internet, such as malware and phishing. This can protect the client’s device and network from cyberattacks and improve their browsing experience. Without advanced filtering, the Company’s cyber assets are at risk of attacks such as ransomware.

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- **Problem Statement:** The Company currently leverages an existing vendor platform for web proxy services that has been in existence since 2021. Since the implementation of the platform, it has caused ongoing operational issues related to web filtering and connectivity. When there is a degradation of service, Company employees and contractors are unable to access internet or cloud-based resources. As the Company continues its cloud and SaaS journey, it is imperative to provide consistent access and communication, while still protecting the Company from cyber threats.
- **Objectives:** This project creates value for the Company by (1) increasing service reliability for employees and contractors to internet and cloud-based resources; (2) utilizing technology to enable the Company to handle all types of different workloads from varying geographic locations and is highly available; (3) using a mature and scalable web proxy service provider; and (4) providing Zero Trust by continuously verifying every connection request.
- **Scope:** The project scope includes: (1) replacing the current web proxy services solution and implementing a new system; (2) replacing physical web proxy hardware; and (3) potentially changing SaaS cloud vendors.
- **Alternatives:** The Security team did extensive research on alternative web proxy services solutions. Alternatives considered included: (1) continue to use and maintain the current web proxy services platform. This alternative was not chosen due to the consistent operational issues with the platform that make it unreliable. The result of an unreliable system means that employees and contractors are unable to access business critical services such as email, Teams, ServiceNow, and SharePoint Online; (2) route all internet traffic through the Company's corporate data center. This alternative was not chosen because the capabilities of firewalls are not as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) replace current system with modern vendor platform for web proxy services. The option that was chosen is to replace the current solution with a new system. This option was chosen because it offers additional features such as browser isolation (the ability to contain web pages so that the web page cannot affect the client workstation) and sandboxing (a way to safely execute malicious applications without impacting the Company's network). As part of the evaluation, the Company reassessed based on outside advisors and industry trend analysis, focusing on the ability to execute and the vendor's capabilities.
- The **Physical Access Management and Alarm Response** project requires \$1,832,660 in capital (\$1,466,128 ROM Adjusted Capital) and \$168,119 in O&M in the test year.
- **Description:** The project will replace the Company's Physical Access Management System to establish a centralized platform that manages user

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identities, authenticates users, authorizes access, and audits user activities. The intent of this project is to consolidate and modernize the Company's physical security systems that will enable enhanced security monitoring to prevent unauthorized entry into sensitive corporate areas while providing increased flexibility to the Company's valued employees and contractors.

- **Problem Statement:** The Company's Security Fusion Center (the Fusion Center is the Company's combined physical and cyber security operations center) is experiencing operational issues with the current physical access management system. The installation is out of date and causes inconsistent behavior when given tasks by automations within the Company's Identity Management solution. Frequent issues have been reported related to frozen jobs in the Company's existing access management solution due to the current system's database. This results in significant waste in the form of (1) waiting, the business partner is waiting much longer than they should have for the system to process their request as un-freezing jobs is a manual process; (2) lost productivity, that waiting can cause for the business partner as it can either prevent them from accessing sites they need, or slow them down unnecessarily while they work with others to be escorted; (3) rework, because frozen jobs do not always run correctly when unfrozen, meaning the business partner has to resubmit their request and/or Identity Operations has to do additional work to satisfy the original request; and (4) alarms can cause a frozen state that impact system stability and reduces security visibility as a result. Not moving to new technology also carries a growing risk of outright system failure which could result in unauthorized physical access and/or impact the Company's ability to efficiently function. The current installation of the physical access management system and the Company's current card readers do not support next generation physical access control methods, such as digital ID. This prevents the Company from adopting new methods and practices that can lower costs and improve control and responsiveness. All employees, contractors, staff, and visitors are impacted by the problem.

- **Objectives:** This project creates value for the Company by: (1) developing an alarm and event monitoring system, which will enable seamless orchestration of system alarms and cameras; (2) adding automation that will streamline remediation processes and orchestrate camera operations for efficiency; (3) refining access revocation and badge access management to ensure only authorized personnel have entry privileges; and (4) introducing new access control readers that will modernize the system, allowing for the use of mobile device badges for employees, contractors, and visitors, offering a more flexible and user-friendly experience for those entering the Company's facilities.

- **Scope:** The project scope includes modernizing the Company's current physical access control system, badge system, badge access hardware and firmware, and all 3000 card readers across facilities and assets. This will

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require modernization of all physical badge access readers and the implementation of hardware and software necessary to run the physical access control system. In addition, there will be substantial automation and integration between the security orchestration solution and the physical access control systems to realize the full benefits of this initiative.

- **Alternatives:** Alternatives considered were: (1) Keeping the current physical access control system and processes as-is. This alternative was not selected as the current platform is outdated, increasingly expensive to support, and does not include modern capabilities, such as digital IDs. It also does not reduce waste, cost, and it does not improve speed to delivery; (2) Developing a custom, in-house physical access control solution that includes modern capabilities, such as digital IDs. This option was not selected as the Company lacks the expertise to build such a solution. Custom-developed solutions have higher long-term costs, and generally result in significant waste, as well as lower speed to delivery; and (3) Implementing a new physical access control system that includes modern capabilities, such as digital IDs, that reduces waste and cost and improves speed to delivery. There are vendors in the market that specialize in physical access control systems that offer proven capabilities the Company is looking to implement. This option was selected as it will allow the Company to meet its objectives of lower waste, lower cost, improved speed to delivery, by implementing digital IDs and enabling tighter integration between the physical access control system and the Company's other security platforms.
- **The Saviynt Enterprise Identity Governance and Access ("EIGA") Implementation** project requires \$432,685 in capital and \$24,936 in O&M in the test year.
 - **Description:** The project will implement Saviynt EIGA module, consolidate Identity Access Management ("IAM") functionality into Saviynt, and retire the Identity Manager application. By implementing the new solution, the Company will optimize IAM functionality, eliminate complexity, and reduce support costs. In addition, the project will integrate the OT network with an IAM solution that will allow for automated management of users and entitlements in the OT Active Directory domains and applications.
 - **Problem Statement:** The current version of AccessNow reached end-of-life in December 2022, with support discontinued in January 2023. The application has numerous custom workflows and integrations, requiring professional services for ongoing use and changes. It lacks proper data analytics and reporting, posing risks such as inability to fix critical defects, software incompatibility, compliance issues, increased costs, and degraded performance. The Company uses multiple IAM tools, each performing critical functions, leading to numerous required interfaces and

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customizations. While beneficial for end users, these integrations increase the risk of system failures, higher support costs, multiple subscriptions, infrastructure and maintenance costs, and more expensive upgrades. The current solution utilizes SAP HR batch file processes that introduces failure points, delays, and data integrity issues. Failures in these processes can prevent new or transferred employees from accessing necessary systems, leading to operational disruptions and potential compliance risks due to inappropriate access retention.

- **Objectives:** This project provides value by: (1) Consolidating multiple IAM platforms through the implementation of the Saviynt EIGA Module, reducing complexity and support costs; (2) Decreasing complexity and enhancing efficiency by reducing interfaces between multiple identity tools; (3) Improving the end-user experience and reducing human struggle with access requests through a new, intuitive portal design; (4) Minimizing custom code and focusing on configurations only by utilizing out-of-the-box functionality; and (5) Streamlining employee data processing with the implementation of an HR interface.
- **Scope:** This project scope includes: (1) Implementing the Saviynt EIGA module to consolidate IAM platforms; (2) Standardizing processes by removing customized code and using out-of-the-box functionality; (3) Replacing and improving access system; (4) Addressing issues with aging applications, multiple IAM platforms, integration challenges, and antiquated HR processing.
- **Alternatives:** Alternatives considered include: (1) Implementing hot fixes to AccessNow version 8.1.5 to ensure support through mid-2023; (2) Upgrading only the application to current supported version, excluding the new web portal but will include new application functionality; (3) Remaining on current version that will be unsupported as of January 2023, requiring vendor professional services for any break/fix. Patches and enhancements may potentially introduce additional risk of version instability; (4) Implementing IAM functions in Saviynt platform to manage access requests, including Active Directory, SAP, SAP HR, disconnected systems, and existing API integrations. The alternative selected was implementing the new Saviynt system, eliminating AccessNow software.
- **The Security/OT Field Modernization** project requires \$149,231 in capital (\$119,385 ROM Adjusted Capital) and \$45,452 in O&M in the test year.
 - **Description:** This project will implement new infrastructure for accomplishing improved security in the field for OT assets.
 - **Problem Statement:** Gas and Electric technicians are using corporate laptops, to manage critical OT infrastructure which does not follow cyber security best practices for managing critical infrastructure. Vendors and

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contractors have access to the Company's critical infrastructure using non-Company laptops. The best practice is to use dedicated laptops to connect to critical infrastructure.

- **Objectives:** The value of this project is deploying dedicated Company OT laptops and associated OT infrastructure that can move between OT locations only and providing a secure environment.
- **Scope:** This project will procure and configure approximately 130 devices that will be used to manage critical OT infrastructure.
- **Alternatives:** The Company reviewed several options to mitigate cyber security risks inherent with the use of standard corporate laptops managing critical infrastructure. The alternatives considered are: (1) Continue utilizing existing workflow of using Corporate domain laptops with software installed; (2) Bring in an outside vendor to design and implement a proposed infrastructure; (3) Complete disallowance of all local access to critical systems; (4) Extending the OT network to remote Company locations; (5) Deploy a dedicated Company OT laptop and OT communications circuits, which includes cellular connectivity. The dedicated OT laptop and communications circuits presented the best way to secure the critical infrastructure by limiting internet and e-mail access. Vendors and contractors could also utilize these approved dedicated systems for managing infrastructure they help support at Company locations. Based on the analysis performed, the Company chose to deploy a dedicated OT laptop and communications circuits.

Q. Overall, are the expenses and expenditures you have identified 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 IRP and EDIIP, continually improve 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 prudence of project expenditures and operational O&M requirements.

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1 I have also provided a detailed synopsis of each project, a supplementary exhibit of
2 the total project cost, hard savings, and cost/benefit analysis for each project in the test
3 year, and a deep dive into benefits for several high-priority projects. This project-specific
4 information demonstrates how IT investments and operational expenses are helping the
5 Company provide exceptional service to its customers. The Company is seeking full
6 recovery for these IT costs that keep its systems available, customers safe from growing
7 cyber security threats, and the Company on a path to the bright future it envisioned in its
8 IRP and EDIIP – one powered by safe, reliable, affordable, clean, and equitable energy.

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

10 A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MARC R. BLECKMAN
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1 **Q. Please state your name and business address.**

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

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

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

7 **Q. What are your current responsibilities?**

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

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

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

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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;

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- Case No. U-20650, the Company's 2019 Gas Rate Case;
- Case No. U-20697, the Company's 2020 Electric Rate Case;
- Case No. U-20722, the Company's RE Plan reconciliation proceeding for 2019;
- Case No. U-20963, the Company's 2021 Electric Rate Case;
- Case No. U-20984, the Company's RE Plan amendment proceeding for 2021;
- Case No. U-21009, the Company's RE Plan reconciliation proceeding for 2020;
- Case No. U-21148, the Company's 2021 Gas Rate Case;
- Case No. U-21197, the Company's RE Plan reconciliation proceeding for 2021;
- Case No. U-21224, the Company's 2022 Electric Rate Case;
- Case No. U-21308, the Company's 2022 Gas Rate Case;
- Case No. U-21352, the Company's RE Plan reconciliation proceeding for 2022;
- Case No. U-21374, the Company's Application for approval of revised Voluntary Green Pricing programs and a RE Plan amendment;
- Case No. U-21389, the Company's 2023 Electric Rate Case;
- Case No. U-21490, the Company's 2023 Gas Rate Case;
- Case No. U-21549, the Company's RE Plan reconciliation proceeding for 2023;
- Case No. U-21585, the Company's 2024 Electric Rate Case;
- Case No. U-21816, the Company's RE Plan amendment proceeding for 2024;
and
- Case No. U-21806, the Company's 2024 Gas 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.

1 **Q. How is your direct testimony organized?**

2 A. My direct testimony is organized as follows:

3 **I. SUMMARY OF RECOMMENDATIONS**

4 **II. CAPITAL STRUCTURE AND COST RATES**

5 **A. Development of Capital Structure**

6 **B. Development of Cost Rates**

7 **III. EXHIBITS FOR CERTAIN FILING REQUIREMENTS –**
8 **CREDIT RATINGS AND RECENT UTILITY BOND**
9 **ISSUANCES**

10 **IV. PROJECTED CASH BALANCE**

11 **V. SHORT-TERM BORROWING FACILITIES**

12 **VI. RENEWABLES LIABILITY**

13 **VII. LINE CLEARING PROGRAM RAMP-UP**

14 **VIII. SUMMARY AND CONCLUSIONS**

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

16 A. Yes. I am sponsoring the following exhibits:

17	Exhibit A-14 (MRB-1)	Schedule D-1	Overall Rate of Return Summary;
18	Exhibit A-14 (MRB-2)	Schedule D-1a	Capital Structure Development;
19	Exhibit A-14 (MRB-3)	Schedule D-1b	Comparison of Development of
20			Capital Structure;
21	Exhibit A-14 (MRB-4)	Schedule D-2	Cost of Long-Term Debt;
22	Exhibit A-14 (MRB-5)	Schedule D-3	Cost of Short-Term Debt;
23	Exhibit A-14 (MRB-6)	Schedule D-4	Cost of Preferred Stock;
24	Exhibit A-14 (MRB-7)	Schedule D-6	Short-Term Debt Utilization;
25	Exhibit A-27 (MRB-8)		Current and Historical Credit
26			Ratings;

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1	Exhibit A-28 (MRB-9)	Recent Utility Corporate Bond
2		Issuances;
3	Exhibit A-29 (MRB-10)	Peer Company Commission
4		Authorized Equity Ratios;
5	Exhibit A-30 (MRB-11)	State Regulatory Evaluations;
6	Exhibit A-31 (MRB-12)	Wells Fargo December 8, 2023
7		Report – Figure of the Week:
8		Approved Equity Ratios, 2005-2023;
9	Exhibit A-32 (MRB-13)	Cumulative Annual Interest Savings;
10	Exhibit A-33 (MRB-14)	S&P Global August 7, 2024 Report –
11		RRA State Regulatory Evaluations –
12		Energy;
13	Exhibit A-34 (MRB-15)	UBS May 10, 2023 Report;
14	Exhibit A-35 (MRB-16)	S&P February 14, 2024 Report;
15	Exhibit A-36 (MRB-17)	S&P August 20, 2024 Credit Report;
16	Exhibit A-37 (MRB-18)	Moody’s May 31, 2024 Credit
17		Report;
18	Exhibit A-38 (MRB-19)	Fitch April 16, 2024 Credit Report;
19	Exhibit A-39 (MRB-20)	Peer Company Revolver Capacity
20		Analysis; and
21	Exhibit A-40 (MRB-21)	S&P January 14, 2025 Report.

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

23 A. Yes.

24 **I. SUMMARY OF RECOMMENDATIONS**

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

27 A. I am recommending that the capital structure shown on page 1 of Exhibit A-14 (MRB-1),
28 Schedule D-1, be used in this case. This represents the actual capital structure as of

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December 31, 2024, 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 April 30, 2027. The development of the capital structure on a ratemaking basis is shown in columns (b) through (d). The equity ratio as a percentage of permanent capital is 50.75%. The equity ratio as a percentage of total capital is 42.94%.

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

A. I am assuming an ROE for Consumers Energy of 10.25%. This ROE is recommended by Company witness Ann E. Bulkley and supported in further detail in her direct testimony.

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

A. I am recommending an overall rate of return of 6.35% 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.

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

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

11 **Q. What is common equity and preferred equity?**

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

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

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

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

3 A. I started with the actual balances of long-term debt, preferred stock, common equity,
4 short-term debt, deferred income taxes, and ITC as of December 31, 2024, as shown in
5 Exhibit A-14 (MRB-2), Schedule D-1a, page 1, column (e). I then made the adjustments
6 shown in column (f) to arrive at the average test year balance ending April 30, 2027, in
7 column (g) that I am recommending be used in this case.

8 **Q. Please explain the common equity adjustment of \$2.511 billion.**

9 A. I have projected that the 13-month common equity balance for the test year will be
10 \$2.511 billion higher than the December 31, 2024 balance. The common equity adjustment
11 of \$2.511 billion consists of two components. The first is an adjustment to reflect
12 \$369 million in projected retained earnings on a weighted average basis from January 2025
13 through April 2027. The second is an adjustment of \$2.142 billion to reflect the projected
14 equity infusions on a weighted average basis from January 2025 through April 2027.

15 **Q. What are retained earnings?**

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

19 **Q. Please explain the retained earnings adjustment of \$369 million.**

20 A. Since I started with the December 31, 2024 balance for common equity, it was necessary
21 to make an adjustment to reflect the increase in the common equity balance through
22 retained earnings that will occur on a weighted average basis through April 30, 2027.

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1 **Q. Please explain how you projected the change in Consumers Energy's retained**
2 **earnings from January 2025 through the test period ending April 2027.**

3 A. Consumers Energy has a long-standing policy of using an 80% dividend payout ratio.
4 I assumed Consumers Energy's retained earnings rate to be \$16.783 million per month, or
5 \$201.4 million per year, from January 2025 through April 2027.

6 **Q. Please explain how you arrived at Consumers Energy's retained earnings rate of**
7 **\$201.4 million per year.**

8 A. Based on Consumers Energy's Securities and Exchange Commission Form 10-K for 2024,
9 I determined that Consumers Energy's net income for the 12-month period ended
10 December 31, 2024, was \$1.007 billion. I used this amount as a proxy for the future net
11 income and assumed a dividend payout ratio of 80%. Using these assumptions, I calculated
12 an annual retained earnings amount of \$201.4 million [$\$1,007 \times (1-0.80)$]. Exhibit A-14
13 (MRB-2), Schedule D-1a, page 3, shows the projected monthly retained earnings balance
14 and calculates the 13-month average for the period ending April 30, 2027.

15 **Q. What are equity infusions?**

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

18 **Q. Why did you make a \$2.142 billion adjustment for the new equity infusions in your**
19 **recommended capital structure?**

20 A. This is the amount needed to hold a 50.75% equity ratio for the test period in this case.
21 CMS Energy made an equity infusion of \$150 million in February 2025 and plans to make
22 equity infusions of \$275 million by May 2025, \$425 million by June 2025, \$40 million
23 by October 2025, \$525 million by February 2026, \$675 million by June 2026, and

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1 \$675 million by February 2027. Accordingly, I reflected this in the equity balance for the
2 test year for this case on a weighted average basis. The impact of these equity infusions
3 on the cumulative balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 3.
4 The 13-month average for the period ending April 30, 2027, is \$2.142 billion. When the
5 13-month average for the equity infusions of \$2.142 billion is combined with the 13-month
6 average \$369 million retained earnings adjustment, the increase to equity capital is the
7 \$2.511 billion shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 1.

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

9 A. My testimony describing the key factors and providing evidence that supports the proposed
10 equity ratio of 50.75% is organized as follows:

- 11 i. Peer Authorized Equity Ratios are Higher and Trending Up
- 12 ii. Equity Ratio/ROE Impact on Credit Quality
- 13 iii. Rating Agencies' Assessment of the Regulatory Environment
- 14 iv. Credit Challenges Facing Regulated Utilities

- 15 i. Peer Authorized Equity Ratios are Higher and
16 Trending Up

17 **Q. How does the 50.75% equity ratio proposed in this case compare to other utilities?**

18 A. To compare the 50.75% equity ratio proposed in this case to other utilities, I researched all
19 rate case decisions of peer companies from 2020 through mid-April 2025 and determined
20 the authorized or approved equity ratio for each. This is reflected on Exhibit A-29
21 (MRB-10). Peer companies for this analysis is defined as regulated subsidiaries of the
22 Company's ROE proxy group reflected on Exhibit A-14 (AEB-1), Schedule D-5, page 2,
23 and excludes orders received by in-state proxy DTE Energy Company as well as the

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Company. The average equity ratio for the peer group was 51.85%, 110 basis points higher than the 50.75% proposed for Consumers Energy in this case.

Q. Are the equity ratios reflected in your sample based on reported financial data or Commission-authorized equity ratios in regulatory proceedings?

A. The equity ratios were taken from Commission orders and public filings and represent actual regulatory equity ratios authorized or approved by different commissions across the country. It is clear from this analysis that, on average, regulatory commissions of the Company's peer group are granting equity ratios that are much higher than the 50.75% that is proposed by the Company in the current case.

Q. Are the utilities included in Exhibit A-29 (MRB-10) companies at the parent holding company level or the regulated subsidiary level?

A. The utilities included in Exhibit A-29 (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,

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1 which are prepared under Generally Accepted Accounting Principles. There are major
2 differences in how components of the capital structure are classified on a ratemaking basis
3 and on a financial basis which would further distort the equity ratios calculated at the parent
4 holding company level.

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

7 A. Yes. In its Order in Case No. U-20963, the Commission stated that “regulatory and
8 financial data should not be combined” with such an analysis. Further, the Commission
9 deemed that such an analysis is invalid assuming one “could not verify that its data
10 contained equity ratios set by a regulatory commission in a rate case.” It is clear from the
11 Commission’s Order that actual commission authorized equity ratios at the regulated
12 subsidiary level as presented in Exhibit A-29 (MRB-10) is the preferred data source for an
13 analysis comparing relative equity ratios of peers.

14 **Q. How does the trend in the Company’s authorized equity ratio compare to other**
15 **utilities?**

16 A. Equity ratios for regulated utilities have increased over the last several years. This trend
17 was highlighted in a December 2023 Wells Fargo report on approved equity ratios. See
18 Exhibit A-31 (MRB-12). As described in the Company’s testimony in previous rate cases,
19 negative cash flow and credit metric impacts occurred when federal tax changes took effect
20 in 2018. In subsequent years, utility commissions adopted higher equity ratios as one way
21 to combat those impacts. The Wells Fargo report shows an increase in approved electric
22 utility equity ratios of 130 basis points from 2019 to 2023. In contrast, the Company’s
23 authorized equity ratio has decreased 205 basis points from 2019 (Case No. U-20322) to

1 present, weakening credit quality and putting the Company's credit rating at risk. The
2 Company has presented data showing that peer authorized equity ratios are significantly
3 higher and are trending up. While this data indicates that a higher equity ratio is warranted,
4 the Company is proposing an equity ratio of 50.75% in this case. This is the minimum
5 amount that, taken together with an ROE of 10.25%, reflects the appropriate level that the
6 Commission should adopt to help preserve Consumers Energy's current credit rating.

7 **ii. Equity Ratio / ROE Impact on Credit Quality**

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

10 A. A key financial metric used by rating agencies is the ratio of Funds From Operations
11 ("FFO") to Debt ("FFO-to-Debt ratio"). The calculation of this financial metric includes,
12 in part, both the equity ratio and the authorized ROE of the Company; thus, there needs to
13 be a balance between the Company's equity ratio and ROE that will ensure that this key
14 financial metric does not degrade and cause significant credit deterioration. An equity ratio
15 of 50.75% and an ROE of 10.25%, as recommended by the Company in this case, results
16 in an FFO-to-Debt ratio that is sufficient in striking this balance.

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

18 A. An FFO-to-Debt ratio is a financial metric that compares a company's cash flow from
19 operating activities to a company's leverage, or debt outstanding. It can also be described
20 as a type of payback ratio, reflecting the Company's ability to repay its outstanding debt
21 with operating cash flow. A higher FFO-to-Debt ratio, one which reflects a higher level of
22 cash flow from operating activities to offset or otherwise reduce the risk associated with
23 the Company's ability to pay its debts, is viewed favorably and indicative of a lower
24 financial risk and a resulting higher relative credit rating. A higher credit rating, in turn,

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1 results in lower financing rates. This is comparable to a bank's credit evaluation for
2 someone requesting a personal loan. After reviewing personal income and outstanding
3 debt, banks generally offer lower financing rates to individuals who have more cash flow
4 to repay debt, indicating a relatively higher credit quality.

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

7 A. As discussed earlier in my testimony, ROE and equity ratio are two inputs in determining
8 the Company's ratio of FFO to Debt, and FFO-to-Debt ratios are used by credit agencies
9 to determine the Company's financial health. Consequently, it is important to recognize
10 that the Company's ROE and equity ratio cannot be evaluated in isolation, but should,
11 instead, be viewed as interconnected components that determine the Company's overall
12 financial health. An ROE of 10.25%, when taken together with an equity ratio of 50.75%
13 results in an FFO-to-Debt ratio that the Company believes is acceptable in the current case
14 and is responsive to recent Commission orders. A lower authorized ROE would, therefore,
15 necessitate a higher approved equity ratio to maintain the same level of financial health.

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

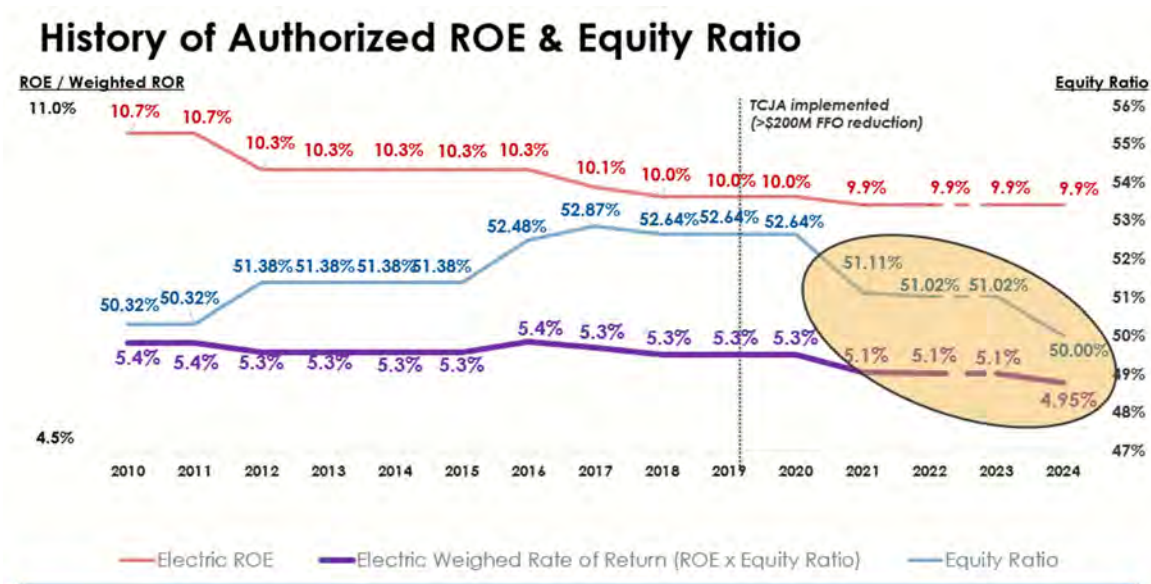
18 A. Multiplying the equity ratio by the ROE produces a weighted cost or "rate of return." This
19 is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1. On line 6 of this exhibit, the
20 equity ratio of 50.75% from column (c) is multiplied by the ROE of 10.25% from
21 column (e) to produce a weighted cost of 5.20%, shown in column (f). This is the weighted
22 cost of common equity, a component of the Company's overall rate of return. This rate of
23 return is important to consider since it takes into account the equity ratio in combination

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with the ROE. As discussed earlier in my testimony, the 50.75% equity ratio and 10.25% ROE is a combination that the Company believes is acceptable in the current case.

Q. What has been the recent trend of the Company's weighted rate of return?

A. Following a long period of stability, recent rate cases have resulted in a sharp decline in rate of return. This is illustrated in the following chart which includes a history of electric authorized ROE, equity ratio, and resulting weighted rate of return.

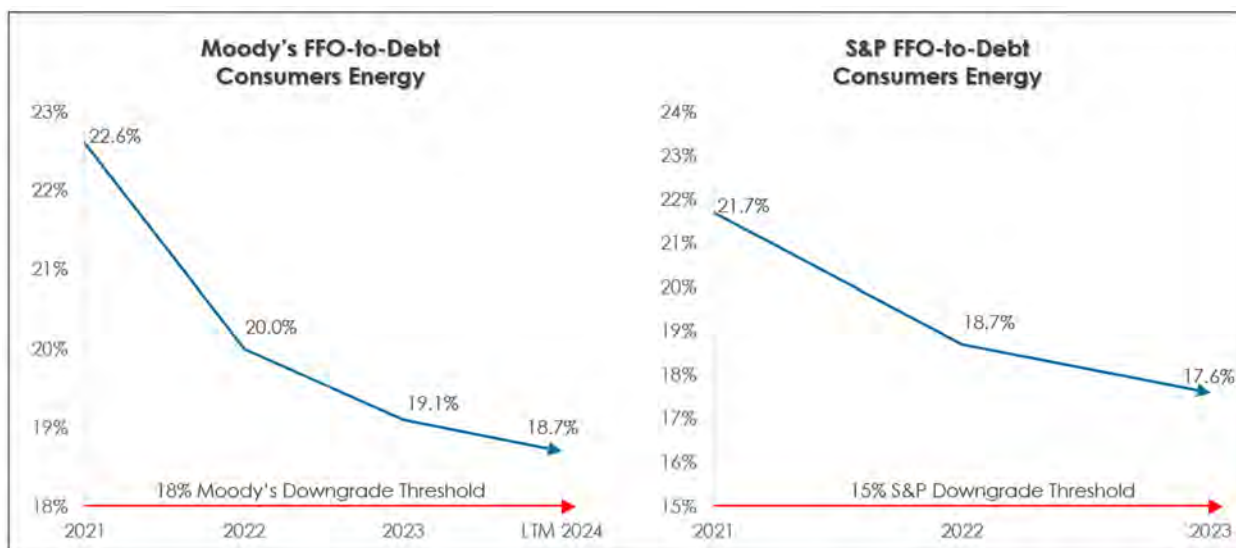


Q. What has been the trend of the Company's credit metrics over the last few years?

A. The Company's FFO-to-Debt ratio as calculated by Standard and Poor's ("S&P") has been trending down in recent years from 21.7% in 2021 to 17.6% in 2023, a decrease of 410 basis points and, for 2023, 40 basis points below the low end of S&P's expected range outlined in its August 2023 report. In addition, the Company's FFO-to-Debt ratio as calculated by Moody's Investors Service ("Moody's") has also been trending down in recent years from 22.6% in 2021 to 19.1% in 2023, a decrease of 350 basis points. Moody's May 2024 credit report also shows a further decline to 18.7% for the 12 months ended March 2024. The Company's FFO-to-Debt ratio as calculated by Moody's is trending

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down and was well below the low end of Moody's expected range (20-21%) for the Company for 2023 and through the first quarter of 2024. These credit metric results are shown in the following chart:



As explained earlier in my direct testimony, recent rate cases have resulted in a sharp decline in rate of return (ROE multiplied by equity ratio). A reduction in the Company's rate of return lowers the Company's cash flow and FFO-to-Debt ratio. The Company also needs to increase its long-term debt to achieve a lower equity ratio. This increase in debt also weakens the Company's FFO-to-Debt ratio. These negative credit metric impacts puts the Company's credit quality and credit ratings at risk.

Q. Are there any new circumstances that could have material impacts on the Company's credit metrics during the test year of this case?

A. Yes. A high degree of volatility and economic uncertainty has emerged in recent months with respect to financial markets, interest rates, and geopolitical tensions. The Trump administration, signaling a significant shift in American trade policy, has placed significantly higher tariffs on imported goods, causing a substantial impact on the U.S. economy. Companies reliant on global supply chains faced elevated input costs, which

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translated into higher consumer prices and contributed to sustained inflationary pressures. In addition, the heightened trade tensions created an atmosphere of uncertainty that negatively affected business investment and led to heightened volatility in financial markets. An April 2025 Wall Street Journal article titled “Huge Stock Swings Are the New Normal for Frazzled Investors” stated that April 2025 is poised to be the most-volatile calendar month since the COVID crash in 2020. The VIX, a stock market index that measures investors’ expectation of volatility, peaked at 52.33 on April 8, 2025. The VIX has not reached 50.00 since April 2020 during the height of the COVID-19 pandemic. Fears of a sharp economic downturn have also dramatically increased. In April 2025, J.P. Morgan Research raised the probability of a U.S. recession occurring in 2025 to 60%. These developments represent a material change in the Company’s risk environment since the previous Commission orders that will most likely continue through the test year of this case. During this period of heightened risk and volatility, it will be critical for the Company to have an authorized ROE and equity ratio that is supportive of its good credit quality. This will be instrumental in the Company’s ability to maintain uninterrupted access to needed liquidity and better withstand potential impacts from fuel price spikes, inflationary pressures, and tightening capital markets. An equity ratio of 50.75% is warranted given the facts and circumstances present in the current case.

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

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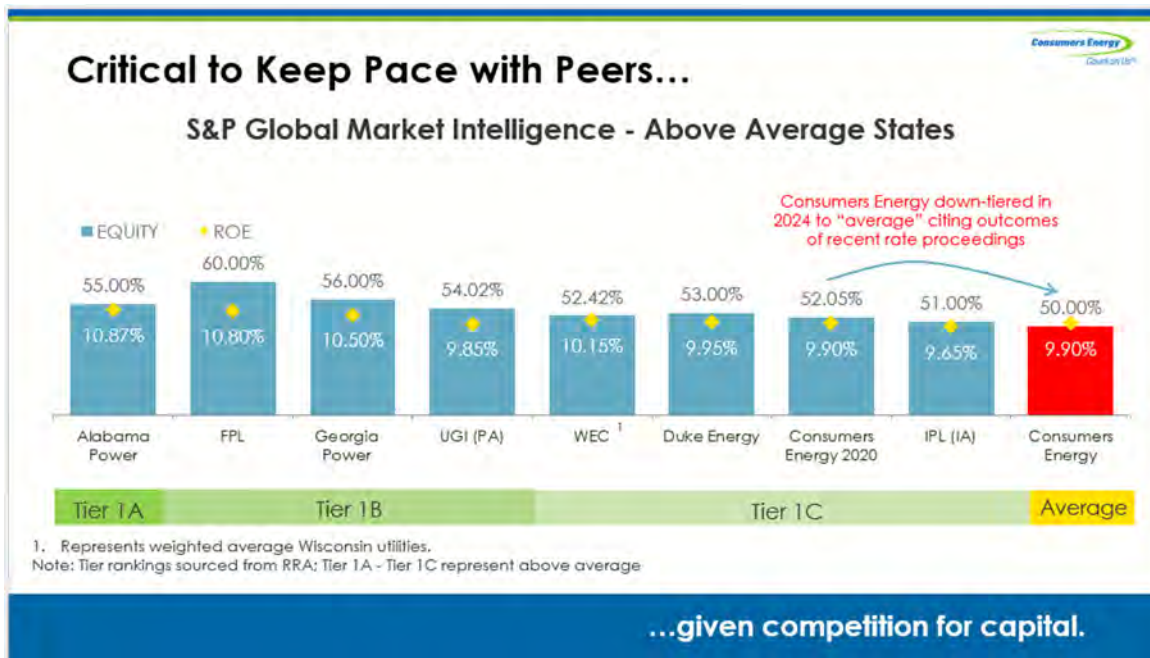
1 exhibits of the Company's multiple capital witnesses, the Company is making significant
2 capital investments to maintain and improve infrastructure to the benefit of customers.
3 During this time, the Company will rely heavily on the capital markets to fund these
4 investments. Generally, a higher credit rating results in lower financing rates. Therefore,
5 it will be especially important for the Company to maintain strong credit ratings over this
6 period. As shown in Exhibit A-32 (MRB-13), the Company has saved customers
7 \$152 million annually as a result of improved credit ratings and lowered interest costs.

8 The common equity balance and equity ratio projected for the test year in this case
9 also enable the Company to maintain strong credit ratings and better withstand any shocks
10 in the financial markets. An example of this was in March 2023, when Silicon Valley Bank
11 and Signature Bank collapsed, forcing the Federal government to step in and take over the
12 banks. Silicon Valley Bank marked the biggest failure of a United States bank since the
13 2008 global financial crisis and led to significant market turmoil. Other large banks such
14 as Credit Suisse and First Republic Bank also experienced significant financial pressure
15 caused by the ensuing market panic. Strong credit ratings can help protect customers from
16 spikes in interest rates which increase the cost of capital, and/or inaccessibility to the capital
17 markets which serve as a key source of financing for the Company's investments on behalf
18 of customers. Strong credit ratings can also enable the Company to issue long-term debt
19 ahead of upcoming maturities ("pre-fund") to take advantage of low interest rates and
20 favorable issuance windows without jeopardizing the Company's financial ratios. When
21 market conditions are favorable, refinancing higher interest rate debt at lower rates reduces
22 the Company's overall cost of capital included in customer rates.

iii. Rating Agencies' Assessment of the Regulatory Environment

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

A. One component of rating agencies' evaluation of credit quality involves an assessment of the Company's regulatory environment. If the Commission demonstrates a pattern of consistent, constructive rate orders, it contributes favorably to the Company's credit quality and credit rating. The authorized equity ratio and ROE are two important components in the rating agencies' assessment of the regulatory environment. Refer to Exhibit A-33 (MRB-14), S&P's State Regulatory Evaluations – Energy. In August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average." This is reflected in the following chart:



In downgrading its state regulatory rating, S&P referenced recent rate case decisions in Michigan including authorized ROEs which "compare less favorably" to prevailing industry averages and a "tightening in the regulatory climate." In recent rate case filings, the Company has included this chart, noting that the recent decline in the Company's

1 weighted rate of return has led to the risk that the Company will no longer be ranked as a
2 utility in an above-average tier jurisdiction. S&P's August 2024 report confirms that this
3 risk has been realized.

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

6 A. Yes. In updating its regulatory rankings for U.S. utilities in May 2023, UBS downgraded
7 Michigan from Tier 1 to Tier 2. In describing the negative change, UBS specifically
8 mentioned authorized ROEs ranking in the 3rd quintile as well as a lowering of their
9 "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's
10 "knowledge of current commission actions." Refer to Exhibit A-34 (MRB-15). It is
11 apparent that rating agencies and analysts are taking note of the Company's regulatory
12 outcomes and are viewing them unfavorably. A continuation or, even worse, a further
13 degradation of the authorized equity ratio and ROE puts the Company at risk of dropping
14 further in its regulatory environment rankings which could negatively impact the
15 Company's credit quality and credit rating. Michigan's above average regulatory standing
16 needs to be protected and bolstered rather than leveraged to justify further credit
17 deterioration and over-leveraging of the Company.

18 **iv. Credit Challenges Facing Regulated Utilities**

19 **Q. Have rating agencies commented on the credit quality of regulated utilities as a**
20 **whole?**

21 A. Yes. Refer to Exhibit A-35 (MRB-16). In a February 2024 report "Rising Risks: Outlook
22 for North American Investor-Owned Regulated Utilities Weakens," S&P updated their
23 outlook of the regulated utility industry to negative, citing "headwinds to credit quality"
24 including increased cash flow deficits that are funded to a higher extent with debt versus

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1 equity. Also refer to Exhibit A-40 (MRB-21). In a January 2025 report on North American
2 regulated utilities, S&P highlighted lower ratings headroom as “a high percentage of
3 companies are operating with only minimal financial cushion from our downgrade
4 threshold.” S&P also notes that, in 2024, downgrades among North America’s
5 investor-owned regulated utilities outpaced upgrades for the fifth consecutive year.
6 With regards to the industry credit outlook for 2025, S&P identifies the following risks
7 to utilities’ credit quality:

- 8 • The portion of equity in the industry has been weak and consistently below
9 expectations and thus pressuring the industry’s financial measures. S&P states
10 that “without significantly more common equity issuance, we expect the
11 industry’s financial measures will continue to weaken, albeit gradually,
12 supporting our negative outlook;”
- 13 • Tax legislation could weaken financial measures if the new Republican
14 administration lowers the corporate tax rate, reduces tax credits, or eliminates
15 their transferability; and
- 16 • Robust capital spending and challenging regulatory constructs will persist for
17 2025, further pressuring the industry’s credit quality.

18 S&P also cites Michigan as one of the regulatory jurisdictions that they “continue to
19 carefully monitor.” As highlighted earlier in my testimony, there has been a sharp decline
20 in the Company’s authorized weighted rate of return following several years of consistent
21 results. It is apparent from this S&P report that a supportive ROE and equity ratio is critical
22 in maintaining a “financial cushion” to protect against downgrade in the event of
23 unforeseen events like the market volatility and disruption that occurred during the onset
24 of the COVID-19 pandemic in 2020 or the financial pressure caused by the dramatic
25 increase in gas prices and interest rates in 2022 or the banking crisis of 2023. These events
26 and rating agency comments highlight the importance for the Company to maintain strong
27 financial metrics and to not manage toward the perceived low end of the credit metric

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bands. The Company's ability to continue to provide customers with safe, reliable, and clean energy and make the necessary capital investments is directly tied to the Company's ability to maintain its financial strength.

Q. Is an equity ratio of 50.75% and an ROE of 10.25% as proposed by the Company in this case the optimal outcome for the Company and its customers?

A. Yes. This equity ratio and ROE combination is well-measured for both the Company and its customers, while still mindful of the Commission's Order in Case No. U-21585. This results in a weighted rate of return of 5.20% (50.75% x 10.25%), which is 25 basis points higher than the weighted rate of return of 4.95% (50.00% x 9.90%) approved in Case No. U-21585. This capital structure results in a reasonable impact on customer rates while bringing the Company more in-line with the authorized weighted rate of return experienced toward the beginning of the COVID-19 pandemic and prior to the most recent credit rating downgrade. The weighted rate of return as proposed in this case strengthens the Company's balance sheet and credit quality which will be critical in delivering the Reliability Roadmap investments while doing so in the midst of a sustained elevated interest rate environment.

Q. Please explain the long-term debt adjustment of \$2.073 billion.

A. I have projected that the average debt balance for the test year ending April 30, 2027, will be \$2.073 billion higher than the December 31, 2024 balance. This adjustment consists of the following components:

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Long-Term Debt (in millions)			Apr. 30, 2027
Month	Issuance	Retirement	Test Year Impact
May 2025	\$475	\$0	\$475
Aug. 2025	\$650	\$0	\$650
May 2026	\$600	(\$115)	\$448
Aug. 2026	<u>\$725</u>	<u>\$0</u>	<u>\$501</u>
Subtotal			\$2,074
Changes in Unamortized Fees			(1)
Total			<u>\$2,073</u>

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

3 **Q. Please describe the planned debt issuances in May 2025, August 2025, May 2026, and**
4 **August 2026.**

5 A. Each of these planned debt issuances will be used for general corporate purposes of the
6 Company including financing capital expenditures. The debt planned to be issued in May
7 2026 will also be used for the retirement of the Company's \$115 million 5.24% bonds
8 which mature in May 2026. These planned debt issuances have been determined based on
9 the Company's financing plans after evaluating cash and liquidity requirements for the
10 Company.

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1 **Q. What long-term debt was included in developing the 13-month average amount**
2 **outstanding for the period ending April 30, 2027?**

3 A. Exhibit A-14 (MRB-4), Schedule D-2, shows the long-term debt that was included in
4 developing the 13-month average for the period ending April 30, 2027. The average
5 amount outstanding on line 64, column (j), ties to the 13-month average balance shown on
6 Exhibit A-14 (MRB-2), Schedule D-1a, page 2.

7 **Q. What is your projection regarding the level of short-term debt balance for the test**
8 **year ending April 30, 2027?**

9 A. I have projected an average short-term debt balance for the test year of \$148 million. This
10 balance is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 10, column (b);
11 Exhibit A-14 (MRB-2), Schedule D-1a, page 1, line 10, column (g); and Exhibit A-14
12 (MRB-5), Schedule D-3, page 1, line 1.

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

14 A. Revolvers, commercial paper, and intercompany borrowing are short-term financing
15 options available to the Company. Revolvers are revolving lines of credit that allow the
16 Company to borrow and repay as long as the outstanding balances remain within the credit
17 limits, or capacity. Commercial paper represents debt issuances under the Company's
18 Commercial Paper Program that are short-term in nature, typically 1- to 90-day maturities.
19 Intercompany borrowing represents short-term borrowings from CMS Energy.
20 Intercompany borrowing is drawn under a promissory note with CMS Energy up to
21 \$500 million and carries an interest rate of 1-month Secured Overnight Financing Rate

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1 (“SOFR”)¹ minus 10 basis points. The Company is the beneficiary of intercompany
2 borrowing to meet short-term liquidity needs when it is available and when it is the most
3 cost-effective alternative. It should be noted that the intercompany borrowing facility is
4 not a dedicated financing option that is always available for the Company to use, but only
5 when CMS Energy has surplus cash and effective borrowing rates must be lower than
6 rates available to the Company under the Commercial Paper Program. The intercompany
7 borrowing facility, therefore, is not considered part of the total liquidity capacity available
8 to the Company.

9 **Q. How was the short-term debt balance of \$148 million developed?**

10 A. Exhibit A-14 (MRB-7), Schedule D-6, shows the projected balances, by month, of
11 short-term debt for the test year ending April 30, 2027. I have arrived at these projections
12 after considering the projected total monthly cash flow requirements, planned long-term
13 debt (net) and equity issuances, and the amount of short-term financing available.

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

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

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

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		<u>Amount</u>	<u>Credit Capacity</u>
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.

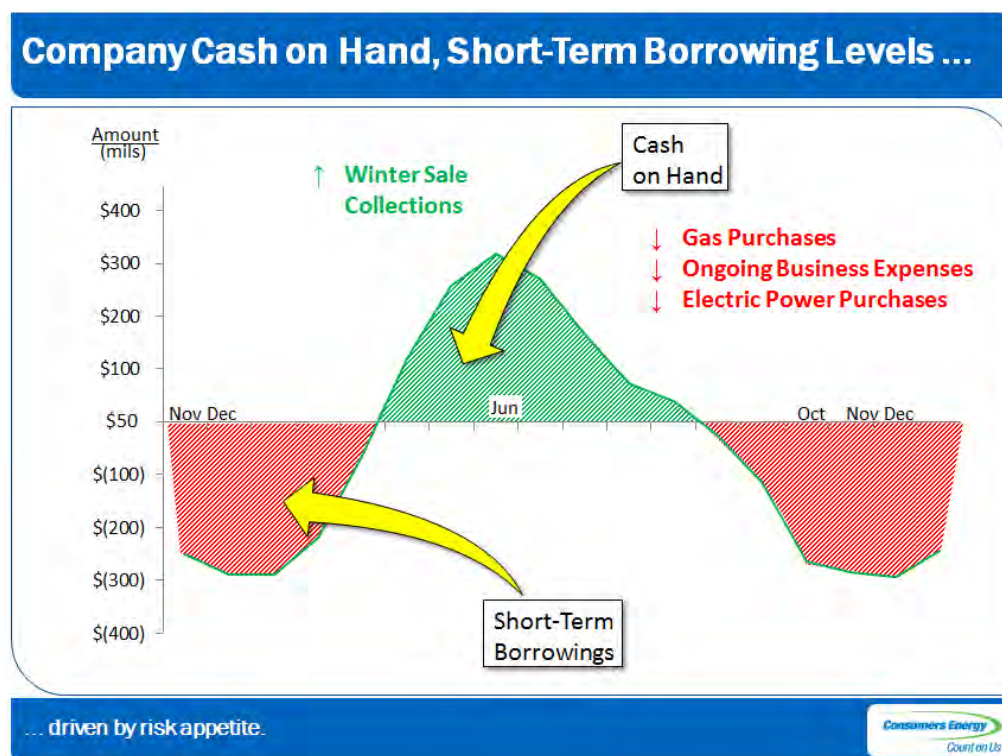
1 All of the projected test year balances for short-term debt are assumed to be issued under
2 the Company's Commercial Paper Program. This program, along with the intercompany
3 borrowing facility, are the least expensive short-term financing options to the Company
4 and are assumed to be used first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

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

10 A. The Company strives to match long-term investments with long-term financing and to
11 finance short-term liquidity needs with its cash and short-term borrowing facilities. The
12 timing and amount of short-term borrowings is directly related to the level of cash on hand.
13 Due to the seasonal nature of utility cash inflows and outflows, the Company generally
14 holds more cash in the spring and summer months and relies on short-term borrowing in

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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

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1 of these seasonal fluctuations, the difference between the maximum working capital
2 surplus and the maximum level of working capital deficiency (peak-to-valley) is
3 approximately \$300 million to \$600 million. The Company is generally comfortable
4 financing between \$200 million and \$400 million of this gap with short-term borrowings
5 as doing so leaves adequate undrawn capacity in the event of financial market volatility or
6 disruption. In addition, rating agencies assess the Company's liquidity as a component of
7 their overall credit rating methodology. Reducing cash balances and relying consistently
8 on short-term borrowings would weaken the Company's liquidity metrics. Finally, if the
9 Company were to establish and maintain a permanent level of short-term debt, this should
10 be taken into account in calculating the appropriate equity ratio in this case. If the
11 short-term debt balance were included in the debt-to-equity ratio calculation, the required
12 equity balance would need to increase in order to achieve the appropriate 50.75% equity
13 ratio. Doing so would result in a higher overall cost of capital.

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

16 A. The Company's projected \$1.35 billion total short-term credit capacity is reasonable and
17 necessary to conduct daily operations and also to keep credit risk at a reasonable level. To
18 maintain strong financial health, it is important for the Company to maintain adequate
19 short-term financing capacity for normal business operations while retaining an adequate
20 amount of additional liquidity for cases of extreme market fluctuations or other unforeseen
21 circumstances. As shown in Exhibit A-14 (MRB-7), Schedule D-6, the Company projects
22 up to \$483 million of short-term borrowings, utilizing most of the \$500 million capacity of
23 the Commercial Paper Program. Access to the commercial paper market, however,

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1 requires an equivalent amount of revolving credit capacity as a “backstop”; therefore, of
2 the Company’s \$1.35 billion of revolving credit facilities, \$500 million is used to support
3 commercial paper issuance. The remaining \$850 million of revolver capacity is a vital
4 backstop for capital expenditures and upcoming long-term debt maturities.

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

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

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1 **Q. Has the Company included the renewable liability balance in its projected short-term**
2 **debt balance?**

3 A. No. Consistent with the Company's RE Plan in Case No. U-21816 filed in November
4 2024, a renewable liability balance is not expected through the test year of this case. As
5 described earlier in my direct testimony, the capital structure in general rate cases is
6 composed of financing components used to fund its operations and capital investment and
7 includes debt, equity, and deferred income tax balances. Since it would be inappropriate
8 to include an asset balance, the Company has thus excluded this component from the
9 projected capital structure. Refer to Section VI. of my direct testimony for additional
10 details of the Company's treatment of the renewable liability balance.

11 **Q. Please explain the deferred income tax adjustment of \$404 million.**

12 A. The Company's Tax Department has projected that the average deferred income tax
13 balance for the test year ending April 30, 2027, will be \$404 million higher than the
14 December 31, 2024 balance. This increase is based on projecting book versus tax
15 differences that the Company expects to record from January 2025 through April 2027.
16 These adjustments total \$404 million on a 13-month average basis for the test year. The
17 development of the 13-month average deferred income tax balance is shown on Exhibit
18 A-14 (MRB-2), Schedule D-1a, page 4.

19 **Q. How was the ITC balance determined?**

20 A. The Company's Tax Department has projected that the average ITC balance for the test
21 year ending April 30, 2027 will be \$148 million, \$26 million higher than the December
22 2024 balance of \$122 million. The balance is based on forecasted balances of both existing
23 and anticipated new ITC credits that the Company expects to record from January 2025

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1 through April 2027. These adjustments total \$26 million on a 13-month average basis for
2 the test year.

3 **Q. What balances did you use for ITC in the proposed capital structure?**

4 A. I allocated the components for ITC based upon the allocation of long-term debt, preferred
5 stock, and common equity in the recommended capital structure.

6 **B. Development of Cost Rates**

7 **Q. Please explain the development of the total weighted cost of capital shown on Exhibit**
8 **A-14 (MRB-1), Schedule D-1, page 1, line 19, column (g).**

9 A. Column (d) represents the percentage of total capital provided by each of the components
10 of the capital structure shown in column (a). These percentages were developed by
11 dividing the amounts of capital shown in column (b) by the total ratemaking capitalization
12 amount shown in line 19, column (b). Column (e) presents the costs, on a ratemaking basis,
13 of each of the components in total ratemaking capitalization. Column (g) is the after-tax
14 weighted cost of capital and is calculated by multiplying column (d) by column (e). The
15 pre-tax weighted cost is shown in column (i) and is calculated by multiplying column (g)
16 by the conversion factors in column (h).

17 **i. Long-Term Debt Cost Rate**

18 **Q. What long-term debt annual cost rate did you use in this case?**

19 A. I developed a 4.54% annual cost for long-term debt. The development of this annual cost
20 rate is shown on Exhibit A-14 (MRB-4), Schedule D-2. Consistent with past Commission
21 practice, the costs are determined on a net proceeds basis. I began with the debt issuances
22 outstanding as of December 31, 2024. I then added the planned new debt issuances in

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May 2025, August 2025, May 2026, and August 2026. These new debt issuances are shown on Exhibit A-14 (MRB-4), Schedule D-2, lines 44 through 47.

Q. Why did you use cost on a net proceeds basis?

A. Not reflecting costs on a net proceeds basis would understate costs. The net proceeds methodology accounts for underwriters' compensation and finance expenses. The fees and expenses are shown as a reduction in proceeds from the issuance of new securities, thereby increasing the cost of the issuance over the stated coupon rate.

Q. Please explain the cost rate you assumed for the planned debt issuances in May 2025, August 2025, May 2026, and August 2026.

A. I assumed that all of the planned debt issuances will be 30-year bonds with a fixed coupon (interest) rate. To calculate the total interest rate (coupon) projection for these bonds, I started with the projected 30-year U.S. Treasury rate. For each of these planned debt issuances, I then added a 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?

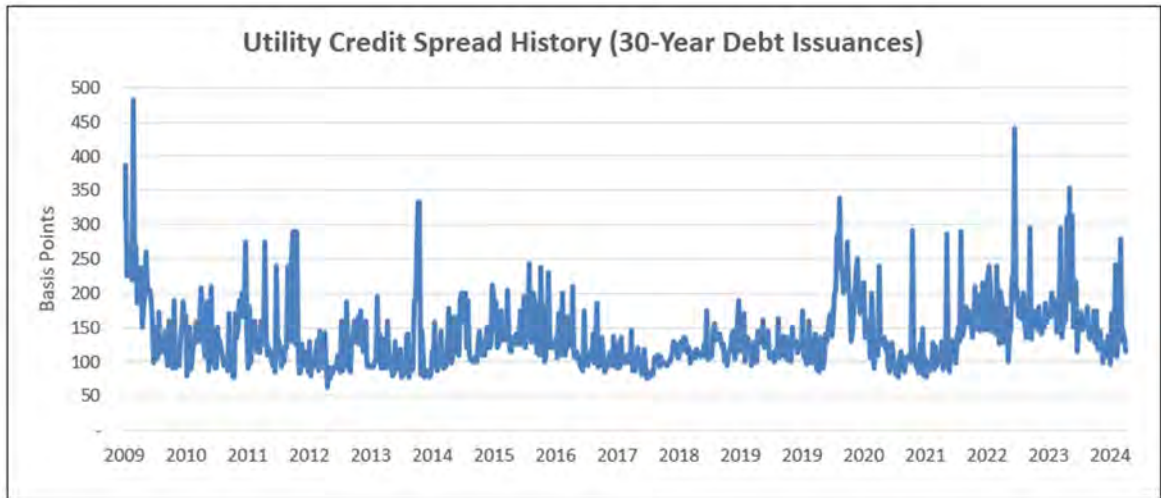
A. A credit spread reflects the compensation investors receive for bearing credit risk of the investment in addition to the underlying Treasury rate. The total interest rate on a corporate bond is the summation of both the Treasury rate and the credit spread.

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

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1 and short-term supply/demand dynamics. In addition, credit spreads can be quite volatile
2 in short periods of time. The volatility of credit spreads is illustrated on the following
3 chart:



4 Given the lack of a reliable source for projected credit spreads, I applied the calculated
5 average from the last 16 years. From 2009 to Mid-April 2025, the average credit spread
6 on a 30-year debt issuance for investment grade utilities was approximately 138 basis
7 points. This credit spread is very reasonable in relation to the historical spreads for 30-year
8 debt issuances, as evidenced in the chart above.

9 **Q. Are there any existing long-term debt issuances that have variable interest rates?**

10 A. Yes. There are three debt issuances shown on Exhibit A-14 (MRB-4), Schedule D-2, which
11 have variable interest rates. The Floating Rate First Mortgage Bonds ("FMB") issuances
12 shown on line 27 and lines 30 through 31 have variable interest rates.

13 **Q. What cost rates did you use for these variable rate issuances?**

14 A. The interest rate for the Floating Rate FMB issuances is equal to SOFR less 4 basis points.
15 Therefore, I took the projected three-month SOFR for the test year in this case (equal to
16 3.34%) and subtracted 4 basis points for an interest rate of 3.30%.

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1 **Q. Please explain Exhibit A-14 (MRB-4), Schedule D-2, line 58.**

2 A. Exhibit A-14 (MRB-4), Schedule D-2, line 58, represents the amortization of losses on
3 reacquired Consumers Energy debt (including call premium) for refinancings. This
4 amortization needs to be added to the interest cost on the refinanced debt to determine
5 Consumers Energy's true financing cost for the long-term debt. The Commission
6 recognized recoverability of these costs in establishing the cost rate in Case No. U-16794.

7 **Q. How did you calculate the amount shown on Exhibit A-14 (MRB-4), Schedule D-2,**
8 **line 58?**

9 A. The amount shown on line 58 represents the amortization of losses on reacquired debt with
10 refunding (including call premiums). The projected amortization expense for the 12-month
11 period ending April 2027 is \$4,342,000.

12 **ii. Short-Term Debt Cost Rate**

13 **Q. What short-term debt cost rate did you use in this case?**

14 A. I used a short-term debt cost rate of 4.92%. This cost rate is shown on Exhibit A-14
15 (MRB-5), Schedule D-3, page 1, line 5.

16 **Q. Please explain the cost of short-term debt.**

17 A. I projected a cost of short-term debt of \$7.3 million. The development of this cost is shown
18 on Exhibit A-14 (MRB-5), Schedule D-3, page 2. The cost of short-term debt – revolver
19 has four components:

- 20 1. **Interest on Borrowings** – Equal to the projected outstanding balance times the
21 projected interest rate. The projected balance, all assumed to be commercial
22 paper, is \$148.3 million, calculated on Exhibit A-14 (MRB-7), Schedule D-6.
23 Commercial paper issuances are short term in nature, typically 1- to 90-day
24 maturities. Interest charged on these short-term borrowings are based on
25 several different factors, including market conditions, investor demand, and the
26 tenor (number of days borrowed) of the issuance. I approximated the interest
27 on commercial paper borrowings using the projected SOFR rate for the test year

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of 3.34%. This was multiplied by the projected balance of \$148.3 million. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of \$5.0 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. (“MISO”) 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

1 need to be recovered as part of long-term debt cost. Refer to my later direct testimony
2 which, as directed by the Commission, explains and justifies the cost of the Company's
3 short-term borrowing facilities. The cost of short-term debt – short-term credit facilities
4 represents the cost to provide \$1.35 billion of necessary liquidity to Consumers Energy.

5 **iii. Preferred Stock Cost Rate**

6 **Q. What is the annual cost of preferred stock?**

7 A. The annual cost of preferred stock is shown on Exhibit A-14 (MRB-6), Schedule D-4. This
8 cost is 4.50%.

9 **iv. Common Equity Cost Rate**

10 **Q. What rate did you use for the cost of common equity?**

11 A. Based on my recommended equity ratio of 50.75%, I applied a cost rate of 10.25% for
12 common equity. As explained earlier in my testimony, to the extent that the Commission
13 authorizes a lower equity ratio than that proposed by the Company, a higher ROE is
14 necessary to prevent the potential for adverse credit impacts. The Company's capital
15 structure and ROE recommendations in this case reflect the appropriate levels that the
16 Commission should adopt with that principle in mind in order to preserve Consumers
17 Energy's current credit rating.

18 **v. Other Cost Rates**

19 **Q. What cost rates did you use for the remaining components of the capital structure?**

20 A. Consistent with MPSC ratemaking practice, deferred income taxes are included at zero
21 cost. The cost rates for each of the three components of ITC correspond to the cost rates
22 for long-term debt, preferred stock, and common equity.

1 **III. EXHIBITS FOR CERTAIN FILING REQUIREMENTS –**
2 **CREDIT RATINGS, AND RECENT UTILITY BOND**
3 **ISSUANCES**

4 **Q. Please describe Exhibit A-27 (MRB-8).**

5 A. Exhibit A-27 (MRB-8) is included per the rate case filing requirements. In its
6 December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities
7 include an exhibit that provides current and historical credit ratings with associated
8 outlooks for the previous five years for the utility and its parent company. Exhibit A-27
9 (MRB-8) shows Consumers Energy's and CMS Energy's current and historical credit
10 ratings, along with associated credit outlooks, for the previous five years as published by
11 S&P, Moody's, and Fitch Ratings, Inc. ("Fitch"). The credit ratings include senior secured
12 debt, commercial paper, senior unsecured debt, preferred stock, junior subordinated debt,
13 hybrid preferred securities ratings, and preferred stock ratings.

14 **Q. Please describe Exhibit A-28 (MRB-9).**

15 A. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that
16 utilities include an exhibit that provides certain information related to bond issuances.
17 Exhibit A-28 (MRB-9) shows recent public utility corporate bond issuances for a period of
18 three months prior to and three months subsequent to, each of Consumers Energy's
19 long-term public debt offerings issued during the 24 months prior to the date of the
20 Application in this rate case. This summary includes the issue date, issuing company, type
21 of offering (either secured or unsecured), amount of offering, coupon rate, S&P and
22 Moody's credit ratings, maturity date, and spread on U.S. Treasury.

1 **IV. PROJECTED CASH BALANCE**

2 **Q. Do you believe that the projected cash balance for the test year ending April 30, 2027,**
3 **should be based on the 13 months ended December 31, 2024 (the working capital**
4 **historical period)?**

5 A. No. Using the 13 months ended December 2024 results in a cash balance of \$36.4 million,
6 which is lower than is normally expected and required for the Company in the test year of
7 this case.

8 **Q. What do you believe that the projected cash balance for the test year ending April 30,**
9 **2027 should be based on?**

10 A. I believe that the projected cash balance for the test year in this case should equate to
11 approximately 1% of test year electric revenues, which results in a cash balance of
12 \$50.4 million. This is reflective of normal levels of cash balance.

13 **Q. In its Order in Case No. U-21585 (the Company’s previous electric rate case), the**
14 **Commission instructed the Company in its next electric rate case to “provide further**
15 **and a more specific explanation as to why its approach in determining its working**
16 **capital cash balance remains appropriate and should continue to be approved.” How**
17 **do you respond to this order?**

18 A. My testimony describing the key factors and providing evidence that supports the
19 Company’s projected test year cash balance of \$50.4 million, or approximately 1% of test
20 year electric revenues, is organized as follows:

- 21 i. The Company’s Cash Projection Approach is Consistent and
22 Balanced
- 23 ii. The Company’s Cash Projection Approach Minimizes
24 Liquidity Risk

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- 1 iii. The Company's Actual Cash Balances Have Approximated
2 1% of Operating Revenues
- 3 iv. The Company's Cash Balances Are a Component of Rating
4 Agencies' Assessment of Credit Quality
- 5 i. **The Company's Cash Projection Approach is Consistent**
6 **and Balanced**

7 **Q. In previous rate cases, has the Company been consistent in projecting the test year**
8 **cash balance equal to approximately 1% of test year revenues by making an**
9 **adjustment in order to reduce the projected cash balance for the test year?**

10 A. Yes. The Company has utilized its approach in projecting the test year working capital
11 cash balance consistently and in a balanced manner. Refer to Case Nos. U-21148 and
12 U-20963. In those cases, the historical period included several months in 2020, in which
13 the country experienced extreme volatility, disruption, and illiquidity in the financial
14 markets related to the COVID-19 pandemic. During this time, the Company took a
15 proactive approach by issuing long-term debt and temporarily holding elevated cash
16 balances. These actions limited the Company's risk of being unable to raise needed capital,
17 strengthened the Company's liquidity, and ensured funding for the continued operations of
18 the Company during this uncertain time. As a result of these actions, however, using the
19 historical period that included 2020 in those cases would have resulted in a cash balance
20 that was higher than what is normally expected and required for the Company. As a result,
21 in those cases the Company used cash balances from an alternative historical period that
22 more appropriately reflected normal, lower levels of cash balances. While there are myriad
23 factors that affect cash balances at any point in time (such as weather, storm costs, and gas
24 prices) making actual cash balances higher or lower than expected, the Company

consistently projects normal cash levels which equates to approximately 1% of test year revenues.

**ii. The Company's Cash Projection Approach
Minimizes Liquidity Risk**

Q. Does the Company's projected cash balance for the test year in this case equating to approximately 1% of test year electric revenues reduce liquidity risk?

A. Yes. Having adequate cash on hand reduces the Company's reliance on short-term borrowing facilities for long periods of time. 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. As described earlier in my testimony, the Company does not pursue a strategy that maintains a permanent balance of short-term debt, however, the Company does fund seasonal fluctuations in its working capital with short-term debt. The Company's projected cash balance for the test year in this case is reflective of normal levels of cash that are expected and necessary for the Company to manage working capital requirements and manage financial risk.

Q. In addition to managing financial risk, what are some benefits associated with the Company maintaining a cash balance equal to approximately 1% of test year revenues as projected by the Company?

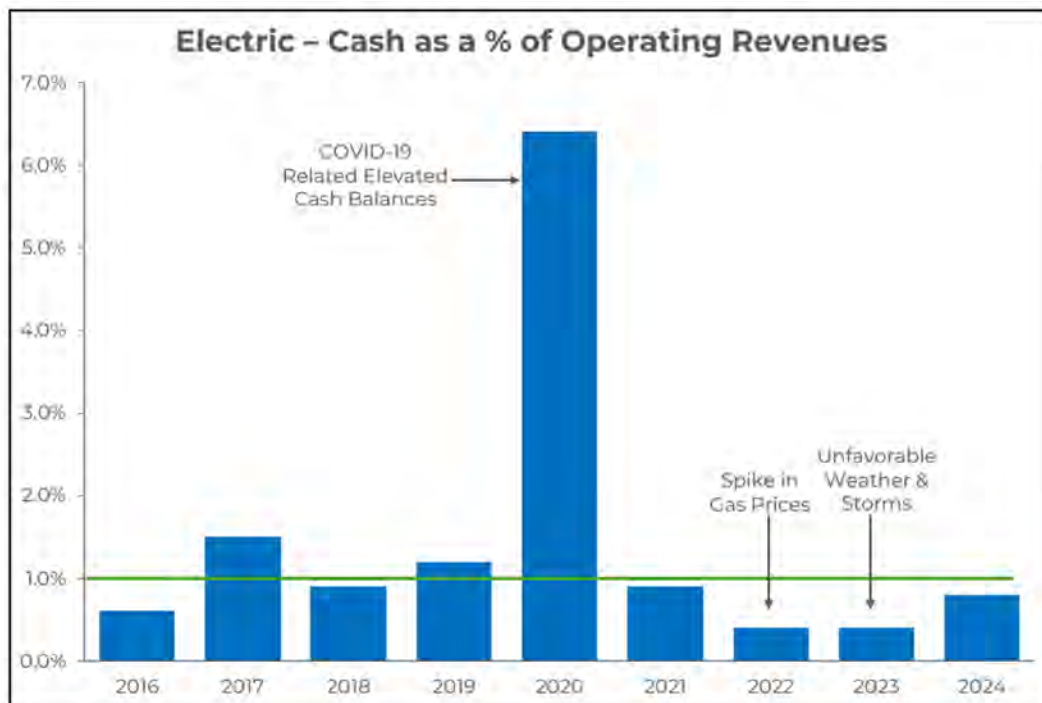
A. In order to obtain an attractive interest rate for long-term bond financing and to minimize the refinancing risk, the Company at times issues new bonds a few months in advance of the actual maturity. Having adequate levels of cash on hand allows the Company additional flexibility in securing the lowest interest rate on its long-term debt issuances which benefits the Company and customers. In addition, given the Company's large capital expenditure

program, the Company aims to maintain an overall liquidity that is sufficient to carry out not only the day-to-day operations but also have the flexibility to meet investing activities should there be a delay in accessing long-term capital from capital markets. For these reasons, the Company's projected cash balance included in working capital for the test year in this case is reasonable and is supportive of the Company's operating, investing, and financing activities.

iii. The Company's Actual Cash Balances Have Approximated 1% of Operating Revenues

Q. Has the Company shown that its actual cash balances have approximated 1% of operating revenues over the last several years?

A. Yes. Refer to the following chart which shows a history of the Company's actual cash balances as a percentage of operating revenues from 2016 to 2024:



The chart shows that the Company's actual cash balances have approximated 1% of operating revenues with the exception of 2020, 2022, and 2023. In 2020, as described

1 earlier in my testimony, the Company temporarily held elevated cash balances related to
2 the COVID-19 pandemic. In 2022, the spike in gas prices forced the Company to use cash
3 on hand as well as short-term borrowings to fund these higher gas purchases resulting in
4 lower than normal cash balances. In 2023, the Company experienced unfavorable weather
5 as well as storm restoration activity well beyond the five-year historical average. Both of
6 these conditions negatively affected the Company's operating cash flows and cash
7 balances. For the years in which the Company's cash balances were unusually higher or
8 lower than normally expected, the Company adjusted its rate case projected cash balance
9 (higher or lower) to account for these deviations.

10 **iv. The Company's Cash Balances Are a Component**
11 **of Rating Agencies' Assessment of Credit Quality**

12 **Q. Does the Company's cash balance impact its credit rating and credit quality?**

13 A. Yes. For example, S&P uses a quantitative measure in assessing liquidity in its evaluation
14 of the Company's credit quality. With this measure, S&P looks at cash on hand and
15 projected cash sources and uses in determining the Company's "liquidity cushion." In its
16 ratings methodology document, S&P describes liquidity as "an important component of
17 our financial risk assessment across the entire rating spectrum... In our view, unlike most
18 other rating factors that we blend together in assessing an issuer's risk profile, a lack of
19 liquidity could precipitate the default of an otherwise healthy entity." Another rating
20 agency, Moody's, has commented on liquidity as saying "we consider liquidity a key
21 element of our analysis of regulated electric and gas utilities." In assessing the Company's
22 credit quality, Moody's performs a similar analysis of the Company's liquidity cushion and
23 flexibility as S&P, estimating the Company's ability to meet near-term anticipated cash
24 requirements using its available sources. The third major credit rating agency, Fitch, also

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1 has a liquidity measure which is calculated as the amount of readily available cash and
2 credit capacity to service or meet debt maturities and interest obligations. This score
3 indicates if the Company has adequate headroom with cash on hand to cover its operating
4 and short-term liquidity requirements. It is apparent that all three major credit rating
5 agencies consider the level of cash on hand to be an important component of their
6 assessment of the Company's credit quality and credit rating. In summary, the Company
7 has shown that its projection of the working capital cash balance equating to approximately
8 1% of test year electric revenues results in a level that is needed, reasonable, balanced, and
9 adequately minimizes the Company's financial and credit risk.

10 **V. SHORT-TERM BORROWING FACILITIES**

11 **Q. In its Order in Case No. U-21585 (the Company's previous electric rate case), the**
12 **Commission instructed the Company in its next electric rate case to "explain and**
13 **justify the size and expense associated with its short-term borrowing facilities if only**
14 **a very small portion is being or has been utilized. The purpose of such an analysis**
15 **should be to determine if the size of such borrowing facilities is reasonable and to**
16 **ensure that the potential benefits of maintaining these facilities is commensurate with**
17 **their expense." How do you respond to this directive?**

18 **A.** My testimony will show that the Company's short-term borrowing facilities are
19 appropriately sized, comparable to other utilities, and are utilized in a manner that
20 minimizes liquidity risk to the protection and benefit of the Company and customers.

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1 **Q. In its Order in Case No. U-21585, the Commission described the Company's**
2 **short-term borrowing facilities as "only a very small portion is being or has been**
3 **utilized." Are the Company's short-term credit facilities also used in a way other**
4 **than cash draws or borrowing?**

5 A. Yes. As explained earlier in my direct testimony, the Company issues letters of credit to
6 cover ongoing operating activities such as fuel purchases or margin support and also to
7 cover MISO margin obligations. The Company's credit facilities provide a necessary and
8 required backstop against these letters of credit. The use of letters of credit is normal and
9 customary for utilities in conducting ongoing business operations. While not considered a
10 cash draw, the Company is utilizing its credit facilities as issued letters of credit reduce the
11 credit capacity of those facilities.

12 **Q. What are the risks associated with the Company borrowing more heavily on its**
13 **short-term credit facilities, effectively reducing its credit capacity and total liquidity?**

14 A. To maintain strong financial health, it is important for the Company to maintain adequate
15 short-term financing capacity for normal business operations while retaining an adequate
16 amount of additional liquidity for cases of extreme market fluctuations or other unforeseen
17 circumstances. Just as it would be unwise for families to plan to max out their credit cards,
18 maxing out or borrowing heavily on short-term credit facilities is not a sound liquidity
19 strategy for the Company and customers. Short-term financing markets can be volatile
20 and, at times, access to those markets completely disappear, as was witnessed during the
21 2008 credit crisis, again in March 2020 as a result of pandemic-related market fear, and
22 again in March 2023 during the banking industry turmoil. Thus, borrowing more heavily
23 on the Company's short-term borrowing facilities creates greater liquidity risk, not to

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1 mention the higher relative cost to draw on those facilities during periods of financial
2 market disruption and interest rate spikes. as explained earlier in my direct testimony, the
3 Company does not pursue a strategy that maintains a permanent balance of short-term debt,
4 however the Company does fund seasonal fluctuations in its working capital with
5 short-term debt. The Company's short-term credit capacity is reasonable and necessary to
6 conduct daily operations and also to keep credit risk at a reasonable level.

7 **Q. How does the cost of the Company's short-term credit facilities benefit the Company**
8 **and its customers?**

9 A. Short-term credit facilities play a critical roll in supporting the Company's financial
10 strength and stability. Even when there are no outstanding borrowings, the cost of these
11 facilities provides essential protection against unexpected short-term financing market
12 disruptions as described earlier in my direct testimony. This is no different than an
13 individual bearing the cost of a home, auto, or life insurance policy which may not be
14 utilized for periods of time but are nonetheless customary and necessary to maintain in case
15 of unforeseen events. In addition, the Company's short-term credit facilities allow the
16 Company to issue letters of credit which, as explained earlier in my direct testimony, are
17 customary and necessary in conducting normal business operations. Thus, the cost of the
18 Company's short-term credit facilities (even with little or no outstanding borrowings)
19 benefits the Company and customers by providing enhanced financial strength and security
20 and supporting business operations.

21 **Q. Does short-term credit capacity impact the Company's credit quality?**

22 A. Yes. The Company's short-term credit capacity, along with cash on hand, is a component
23 of liquidity. Refer to my earlier testimony which explains how the Company's liquidity is

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1 a key factor in rating agencies' assessment of the Company's overall financial health.
2 Based on guidance issued by all three major credit rating agencies, it is apparent that the
3 Company's liquidity (which includes short-term credit capacity) is an important
4 component of their assessment of the Company's credit quality and credit rating.

5 **Q. Do the rating agencies consider the Company's liquidity including short-term credit**
6 **capacity to be excessive?**

7 A. No. Refer to Exhibit A-36 (MRB-17). In August 2024, S&P assessed the Company's
8 liquidity, including its short-term credit capacity, as "Adequate," noting that their rating
9 reflected the Company's "prudent risk management." Also refer to Moody's May 2024
10 credit rating reflected on Exhibit A-37 (MRB-18). In its credit evaluation, Moody's stated
11 "we expect Consumers Energy's liquidity profile to be adequate over the next 12-18
12 months." Finally, refer to Exhibit A-38 (MRB-19), Fitch's April 2024 credit opinion. In
13 its assessment, Fitch identified the Company's revolving credit facilities as supporting
14 short-term liquidity needs and rated the Company's liquidity as "adequate." It is clear from
15 these reports that the consensus among rating agencies is that the Company's short-term
16 credit capacity is not considered excessive, but is rather "adequate" considering the
17 Company's liquidity needs and provides a suitable cushion to protect against times of
18 economic stress and financial market disruption. A greater reliance on the Company's
19 short-term credit facilities would result in a reduction in that credit capacity, leading to a
20 weakening of the Company's liquidity profile and credit quality.

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1 **Q. How does the dramatic increase in gas prices in 2022 highlight the importance of the**
2 **Company's short-term credit capacity?**

3 A. The spike in gas prices in 2022 forced the Company to use cash on hand as well as
4 short-term borrowings to fund these higher gas purchases. In order to meet the increased
5 short-term borrowing needs caused by significantly higher gas prices while avoiding
6 maxing out its current short-term borrowing facilities, the Company secured a term loan
7 allowing the Company to borrow up to \$1 billion. This significantly reduced liquidity risk
8 while ensuring continued short-term borrowing at reasonable interest rates. While the
9 Company was able to secure a \$1 billion term loan in July 2022 to meet the excessive
10 short-term borrowing requirements, access to this type of facility at reasonable interest
11 rates is never guaranteed in the future, particularly during times of extreme capital market
12 volatility or the inability to access those markets. The dramatic increase in gas prices in
13 2022 and the resulting elevated short-term borrowing levels highlights the importance of
14 maintaining sufficient short-term credit capacity to ensure that the Company is able to
15 adequately fund gas purchases, continue operations, and serve customers.

16 **Q. Is the size of the Company's short-term credit facilities in line with that of other**
17 **utilities?**

18 A. Yes. Refer to Exhibit A-39 (MRB-20). At year-end 2024, peer companies maintained, on
19 average, a ratio of revolving credit facilities to net Property Plant and Equipment of 5.4%.
20 The Company's credit capacity of 5.3% is just below other companies in the utility
21 industry.

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1 **Q. Have other utilities been increasing their short-term borrowing capacity?**

2 A. Yes. Refer to Exhibit A-40 (MRB-21). In a January 2025 report on North American
3 regulated utilities, S&P highlights rising capital expenditures over the past decade focused
4 on safety, reliability, and investment in renewable generation. S&P predicts record capital
5 spending in the industry in 2025. As utilities' capital spending has continued to rise, so
6 too has companies' short-term liquidity needs. Recently, there have been multiple
7 examples of other utilities increasing their short-term borrowing capacity. For example, in
8 April 2025, Dominion Energy increased its short-term borrowing capacity by \$1.1 billion
9 from \$6.9 billion to \$8.0 billion, underscoring its commitment to maintaining a strong
10 financial foundation for its operations and future growth initiatives. Also, in March 2025,
11 Southern Company increased its short-term borrowing capacity by \$1.0 billion from
12 \$7.9 billion to \$8.9 billion. Finally, Duke Energy increased its credit facility from
13 \$9 billion to \$10 billion in March 2025. In its announcement of the credit capacity
14 upsizing, the company noted: "The expansion and extension of the credit facility
15 underscore Duke Energy's commitment to maintaining robust financial health and
16 supporting its operational and strategic initiatives. This development is expected to provide
17 the company with greater liquidity and an extended timeline to leverage financial resources
18 effectively." It is clear that other utilities are increasing their short-term credit capacity in
19 order to meet growing liquidity needs and enhance financial flexibility. An adequate
20 amount of short-term borrowing capacity will also be critical for Consumers Energy as it
21 executes its capital investment plan to support a more reliable, resilient, and increasingly
22 clean energy system for its customers as outlined by the Company's capital witnesses in
23 this case.

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1 **Q. Has the Company explained and justified its short-term borrowing facilities as**
2 **directed by the Commission in Case No. U-21585?**

3 A. Yes. My testimony has shown that the Company's short-term borrowing facilities are
4 appropriately sized and are in line with peer utilities on average. As with other utilities,
5 the Company's robust capital investment plan will require an adequate amount of credit
6 capacity to meet growing short-term liquidity needs. My testimony has also shown that
7 the Company's short-term credit capacity has a direct impact on credit quality and credit
8 ratings, with all three major credit rating agencies assessing the Company's liquidity as
9 "adequate." Finally, my testimony has shown that the Company's utilization of its
10 short-term borrowing facilities is reasonable and prudent and benefits customers by
11 effectively minimizing liquidity risk.

12 **VI. RENEWABLES LIABILITY**

13 **Q. In its Order in Case No. U-21585 (the Company's previous electric rate case), the**
14 **Commission instructed the Company in its next electric rate case to "provide a more**
15 **thorough explanation of its renewables liability short-term debt process, consistent**
16 **with the Commission Staff's recommendations in this case." How do you respond to**
17 **this directive?**

18 A. The primary concern expressed by Staff witness Kirk D. Megginson in Case No. U-21585
19 was that the renewables liability, representing excess funds collected through the
20 Company's renewable energy program, is improperly "being charged back to customers as
21 a form of short-term debt." However, interest on the renewable liability reduces the
22 revenue requirement in the Company's renewable energy case and is therefore a benefit to
23 renewable customers. In addition, in previous rate cases, the Company has consistently

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1 included the renewables liability as a component of short-term debt in its general rate case
2 capital structure projections consistent with energy legislation. Finally, while not projected
3 or included in the current case, the Company is not opposed to excluding a renewables
4 liability balance from its capital structure should a liability be projected in future cases.

5 **Q. Has the Company’s treatment of the renewables liability been in compliance with**
6 **long-standing ratemaking history and Michigan legal precedent?**

7 A. Yes. Section 21(4) of Public Act 295 of 2008 discusses the cost rate for the renewable
8 liability, and it provides for “the creation of a regulatory liability that accrues interest at the
9 average short-term borrowing rate available to the electric provider during the appropriate
10 period.” Although Section 21 was repealed by Public Act 235 of 2023, Section 22(1) of
11 Public Act 235 specifies that previously approved revenue recovery mechanisms under
12 Section 21 remain in effect. The Commission has approved this methodology since the
13 beginning of the renewable portfolio requirements of Public Act 295 in 2008.

14 **Q. If the Company had excluded the renewables liability from its capital structure,**
15 **would the total cost of capital have decreased?**

16 A. No. Long-term debt and common equity, which make up the vast portion of the Company’s
17 capital structure, are more expensive than the renewables liability which is based on
18 short-term interest rates. Therefore, removing the renewables liability from the capital
19 structure would effectively increase (though marginally) the Company’s total cost of
20 capital used in the rate case revenue requirement calculation.

1 **Q. Has the Company included the renewable liability balance in its projected short-term**
2 **debt balance in this case?**

3 A. No. Consistent with the Company's RE Plan in Case No. U-21816 filed in November
4 2024, a renewable liability balance is not expected through the test year of this case. As
5 described earlier in my direct testimony, the capital structure in general rate cases is
6 composed of financing components used to fund its operations and capital investment and
7 includes debt, equity, and deferred income tax balances. Since it would be inappropriate
8 to include an asset balance, the Company has thus excluded this component from the
9 projected capital structure.

10 **Q. In his direct testimony in Case No. U-21585, Staff witness Megginson recommends**
11 **that the Commission eliminate the renewables liability balance from the Company's**
12 **rate case capital structure. Is the Company agreeable to this recommendation?**

13 A. Yes. Although the Company has treated the renewables liability balance consistent with
14 long-standing ratemaking practice and legislative authority, the Company does not object
15 to excluding the renewables liability balance from its capital structure should a liability
16 balance be projected in the future.

17 **VII. RATE OF RETURN NECESSARY FOR LINE CLEARING**
18 **PROGRAM "RAMP-UP"**

19 **Q. What does the Company propose with respect to its Low Voltage Distribution**
20 **("LVD") Line Clearing Program expenditures in this case?**

21 A. As detailed in Company witness Patrick D. Daly's direct testimony, the Company is
22 proposing to increase its LVD Line Clearing Program operating and maintenance
23 ("O&M") expenditures significantly above historical levels toward attaining a five-year
24 clearing cycle and more aggressive line clearing on targeted three phase primary lines. The

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1 Company is seeking approval in this case to defer the “ramp-up” related expenses as a
2 regulatory asset once the “ramp-up” begins and through its completion (i.e., beginning in
3 2026 and through the 2030-2031 test period).

4 **Q. What rate of return must the Company receive on the deferred expenses during the**
5 **“ramp-up” deferral period?**

6 A. The Company’s proposal to securitize the deferred expenses is conditional on the ability to
7 receive the prevailing pre-tax weighted average cost of capital (“pre-tax WACC”) on the
8 balance of the regulatory asset until the costs are securitized. Due to the long-term nature
9 of the deferred expenses, the Company intends to fund the “ramp-up” with a mix of
10 long-term debt and equity, aligned with the Company’s approved capital structure.
11 Consequently, the appropriate interest rate to be applied to the regulatory asset should be
12 based on the Company’s prevailing pre-tax WACC during the “ramp-up” period and until
13 securitization occurs.

14 **Q. Why is the Company’s short-term debt rate not an appropriate financing rate for the**
15 **deferred “ramp-up” regulatory asset?**

16 A. Since the regulatory asset will not be short-term (i.e., less than one year), the Company
17 cannot finance the regulatory asset with debt. Doing so would add additional strain to the
18 Company’s credit metrics on top of the strain that has been described throughout this
19 testimony resulting from the material reductions in authorized ROE and equity ratio
20 combined with the unfavorable impacts of the Tax Cuts and Job Act of 2017 and current
21 macro-economic uncertainties. Therefore, using the short-term (or long-term) debt rate
22 would not appropriately match the financing costs with the return the Company earns on
23 the regulatory asset. Thus, the Company’s total weighted average cost of capital matches

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1 the “ramp-up” related spending and is the appropriate rate to be applied to the regulatory
2 asset.

3 **Q. Aside from whatever rate of return is applied to the regulatory asset balance, does**
4 **this “ramp up” in forestry work create any positive FFO, i.e., cash flow?**

5 A. No. It is important to note that forestry spend is an O&M expense and does not create any
6 FFO for the Company in the form of non-cash depreciation expense that gets collected
7 from customers in rates. During the deferral period, the Company would be absorbing the
8 cash and expense burden to fund the “ramp up” while not collecting any of those costs
9 from customers. This deferral has the effect of increasing long-term financing needs for
10 the Company without creating cash flow the way traditional capital does. This makes the
11 application of a pre-tax WACC on this particular regulatory asset balance all the more
12 important.

13 **Q. Please contrast the credit metric ratio impact of the “ramp up” on a standalone basis**
14 **if a pre-tax WACC or short-term debt rate is applied.**

15 A. Were the regulatory asset funded with short-term debt in lieu of pre-tax WACC, the
16 Company’s FFO would be lower and its debt higher, leaving the standalone FFO-to-debt
17 ratio wholly insufficient. These impacts are calculated in the following table:

FFO/Debt Ratio of Forestry Deferral as Standalone		
<i>Example: \$100 million Regulatory Asset Balance</i>		
	As Filed	Proforma
	<i>(Pre-tax WACC)</i>	<i>(Short-Term Debt)</i>
FFO, mils	\$ 7.4	\$ 4.3
Debt, mils	41.6	84.8
FFO/Debt	17.7%	5.0%
<u>Calculations (Percentages based on Order in U-21585)</u>		
As Filed FFO:	\$100 mil x 7.38% pre-tax WACC	
As Filed Debt:	\$100 mil x 41.6% LT debt pct of total cap.	
Proforma FFO:	\$100 mil x 4.28% short-term debt rate	
Proforma Debt:	\$100 mil x 84.8% (total cap. less DFIT)	

If the prevailing pre-tax WACC is applied, the FFO-to-Debt ratio of the deferral as a standalone would be approximately 18%. It is worth noting, for comparison purposes, that 18% is Moody's downgrade threshold for the Company so this would not add any padding to the Company's position. However, if the same regulatory asset balance is assumed to be financed with short-term debt, the FFO-to-Debt ratio as a standalone would decrease dramatically to approximately 5%. Due to the harmful credit metric impacts, the short-term debt rate is not an acceptable financing assumption for the deferred "ramp-up" regulatory asset.

VIII. 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, 2024, adjusted for the known and expected changes in long-term debt,

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1 common equity, short-term debt, deferred income taxes, and ITC, as shown on Exhibit
2 A-14 (MRB-1), Schedule D-1. The cost rates developed are fair and reasonable and
3 commensurate with the risks for the period of time rates are expected to be in effect. As
4 shown on Exhibit A-14 (MRB-1), Schedule D-1, I recommend an overall after-tax rate of
5 return of 6.35%. Also, the Company's projected cash balance for the test year in this case
6 should be based on approximately 1% of test year electric revenues, which results in a
7 balance of \$50.4 million. Finally, the Company's total weighted average cost of capital
8 should be applied to the regulatory asset associated with the Company's line clearing
9 program ramp up.

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

11 A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

RICHARD T. BLUMENSTOCK
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1 **Q. Please state your name and business address.**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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the generating unit availability projections in Exhibit A-42 (RTB-2). Company witness Metz also supports the capacity value of the Company's generation assets for the seasonal construct in the MISO Planning Resource Auction ("PRA") in Table 2.

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

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

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

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

A. Yes, I am sponsoring the following exhibits:

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

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

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

17 A. Yes.

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

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

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

SECTION I

GENERATION ASSETS

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

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

TABLE 1

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

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

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

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

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

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

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

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

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

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

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

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

GENERATION ASSET STRATEGY

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

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

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

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

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

FIGURE 1

2024 Net Energy Value

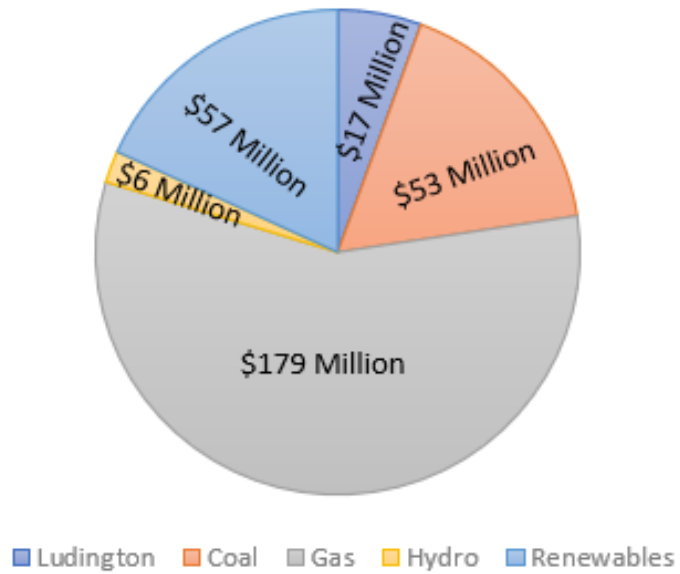
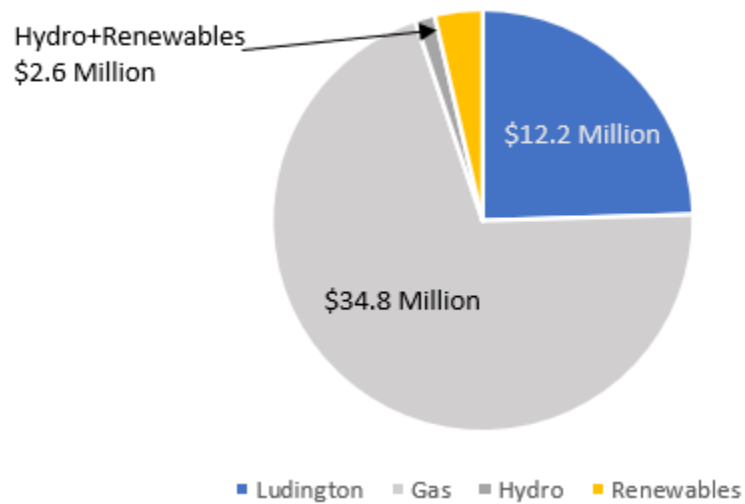


FIGURE 2

Capacity



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

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

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

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

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

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

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

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

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

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

Q. Please define ROR.

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

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

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

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

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

14 **Q. Please define PF.**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

TABLE 2

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SECTION II

ENVIRONMENTAL REGULATIONS

OVERVIEW

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

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

CURRENT (ON-GOING) ENVIRONMENTAL COMPLIANCE

Environmental Regulations – Air Quality

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

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

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

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

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

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

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

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

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

Environmental Regulations and Compliance Strategy – Waste

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

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

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

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

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

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

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

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

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

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

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

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

SECTION III

GENERATION CAPITAL EXPENDITURES

OVERVIEW

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

11 **2024 HISTORICAL TEST YEAR CAPITAL EXPENDITURES**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

13 **PROJECTED TEST YEAR CAPITAL EXPENDITURES**

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

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

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

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

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

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

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

14 **Covert Plant**

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

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

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

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

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

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

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

The basis for these six projects is described below:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

20 **Karn Units 1 and 2**

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

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

Karn Units 3 and 4

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

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

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

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

The basis for these projects is described below:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Zeeland Plant

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Jackson Plant

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

HYDRO UNITS

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

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

LPS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ADMINISTRATIVE AND OTHER

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

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

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

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

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

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

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

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

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

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

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

BATTERY ENERGY STORAGE SYSTEMS

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

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

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

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

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

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

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

GENERATION CAPITAL EXPENDITURES—SUMMARY

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

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

SECTION IV

GENERATION O&M EXPENSE

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

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

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

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

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

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

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

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

HISTORICAL O&M EXPENSE

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

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

Q. How are Generation O&M expenses categorized?

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

Q. What are Base O&M expenses?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

20 **ENVIRONMENTAL OPERATIONS**

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

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

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

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

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

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

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

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

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

10 **MAJOR MAINTENANCE**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Campbell Site Major Maintenance

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

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

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

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

Karn Units 1 and 2 Major Maintenance

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

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

Covert Plant Major Maintenance

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

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

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

Karn Units 3 and 4 Major Maintenance

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

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

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

Zeeland Plant Major Maintenance

Q. Please describe Zeeland Plant Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 6, column (d), Zeeland Plant Major Maintenance expense is forecasted to be \$5.419 million in the projected test year ending April 30, 2027, and includes:

- Zeeland Plant LTSA — Running Maintenance Contract (\$2,395,766). Consumers Energy has a long-term maintenance agreement with General Electric to perform the major maintenance and capital repairs necessary to

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maintain unit reliability. This item represents the O&M component of that service agreement;

- Zeeland Plant Capacity Factor Used for Water and Chemicals (\$1,293,615). This item provides for the city water used by the Zeeland Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;
- Base Outage — Boiler Plant Equipment (\$566,667). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments;
- Large Oil Filled Transformer maintenance (\$250,000). The scope of this project is to execute the 20-year major maintenance plan which includes (1) drain/process/reclaim oil, (2) perform internal inspections when drained, (3) perform planned repairs and evaluate as found conditions, and (4) perform electrical testing to internal circuits and supporting electrical components; and
- Seventeen additional projects totaling \$912,700 in expenses, with each individual project representing \$213,033 or less in expenses. These include drum level control valve overhaul, excitation and isolation transformer testing and maintenance, HEPS, FAC inspection, breaker maintenance, and NERC-required relay testing.

Jackson Plant Major Maintenance

Q. Please describe Jackson Plant Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 7, column (d), Jackson Plant Major Maintenance expense is forecasted to be \$4.112 million in the projected test year ending April 30, 2027. This forecasted expense consists of:

- Jackson Plant Capacity Factor Used for Water and Chemicals (\$2,722,395). This item provides for the city water used by the Jackson Plant and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use. The projected expense is based upon historical monthly invoice values as well as consideration of the capital project previously discussed in this testimony for site generating water;

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- Jackson Plant Non-LTSA Turbine and jet engine repairs (\$400,000). The scope of this major maintenance is to perform jet engine repairs including bushing replacements every 12,000 hours;
- Jackson Plant LTSA — Running Maintenance Contract (\$500,000). Consumers Energy has a long-term maintenance agreement with General Electric to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;
- Jackson Plant Base Outage - Boiler plant equipment (\$250,000). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments; and
- Five additional projects totaling \$240,081 with each individual project representing \$75,000 or less in expenses. These include pre-filter replacement, turbine building temperature control maintenance, chiller condenser cleaning, and NERC relay testing.

LPS Major Maintenance

Q. Please describe LPS Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 9, column (d), LPS Major Maintenance expense is forecasted to be \$4.708 million in the projected test year ending April 30, 2027, including:

- Fish Barrier Net - Installation, cleaning, and repairs and removal (\$2,182,503). This is a FERC regulatory requirement. The net is installed annually and maintained to meet FERC license requirements (and the requirements of a Settlement Agreement with federal and state natural resource agencies) and minimizes the impact of LPS on fish in Lake Michigan;
- Trench Feature Work (\$450,000). FERC Part 12 requires inspections to be performed on reservoirs every 5 years. This project includes performing a dam safety inspection on the upper reservoir clay liner, scour features, erosion gullies and tailrace. The annual reservoir inspection includes multi-beam sonar and side scan of the upper reservoir as well as a multi-beam sonar on the tailrace. The project is to perform engineering remediation on defects found and

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perform silica placement as necessary to remain compliant with FERC regulations;

- Scour Feature Repair Phase 2 and 3 (\$585,667). The project scope includes repairing the scour features on Units 1 and 6 by placing rip rap in the areas where rip rap has been displaced by the newer and more powerful pumping units. Construction would include filling the Unit 1 and Unit 6 scour feature areas with rip rap and fill voids with concrete, and placing 2" of concrete between the rip rap on the entire width of the rip rap apron to a length of about 400'. This would lock in the rip rap throughout the entire width of the 2' rip rap apron and prevent the rip rap apron from being scoured away.

The rip rap apron has experienced more scour due to the upgraded pumping units. The rip rap gets displaced, exposing the filter cloth underneath the rip rap and protecting the clay liner. Once the filter cloth is exposed, it historically has gotten ripped by the pumping units and exposed to the clay liner and potential scour. During the 2019 trench features inspection, the exposed fabric was ripped, exposing the clay liner in front of Unit 6 and allowing for the clay liner to be scoured away. The rip rap apron in front of Unit 1 has also experienced scour, which has moved riprap stone and exposed fabric on top of the clay liner. Since October 2019, the area of exposed clay in front of Unit 6 has grown from 6' diameter to 20' diameter and 1.5' of the 7-8' clay liner has scoured away.

The Company has committed to FERC that it would engineer a repair to address these recurring issues in 2020; engineering was complete in April 2020 and submitted to FERC for FERC approval. In February 2020, the Dam Safety Surveillance Monitoring Committee ("SMC") created threshold action levels for the scour features in concurrence with the Engineer of Record for the scour feature repair. At 0-1 ft of scour of the clay liner, no actions are necessary. At 1-2 ft of scour of the clay liner, the scour feature shall be inspected in the next May or October outage. At 2-4 ft of scour of the clay liner, an emergent repair is needed;

- Nine Year Unit Mechanical Interval Inspection and Replacement (\$358,000). The scope of this project is to perform replacement of common wear elements and consumable items associated with the pump/turbine units. This work will include the first nine-year maintenance interval for each of the six;
- Generator Circuit Breaker ("GCB") Pumping Pole Maintenance (\$200,000). This project will fund the work scope to annually rebuild the pump poles across the site to restore their operational life as per the GCB maintenance strategy. Expected duty cycles and wear rates observed will require the site to average one pump pole set per year with an associated cost around \$200k annually for the site to perform the required maintenance items to restore. This project is only for the pump poles and not the generating poles.

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The GCB contact assembly is configured with both main and arcing contacts. The arcing contacts are designed to be "sacrificial" to prolong the main contact life. The GCB cannot safely operate under a fault condition once the arcing contact life is expended at 25% life remaining, which will force the unit to be unavailable in pump mode operations until the proper maintenance is performed. The GCB pole maintenance must be addressed in a planned outage prior to reaching 25% calculated life remaining to mitigate costs of an individual outage just for GCB maintenance; and

- Twenty-three additional projects totaling \$932,059, with each individual project representing less than \$161,000 in expenses. These include Station Drainage Sump and oil/water separator cleaning, wicket gate repair, Depression Air Compressor Maintenance, periodic outage inspections and non-destructive examination, 480v Transfer bus clean and inspection, and Non-Destructive Inspection Of Insulated And Critical Piping Systems.

Hydro Major Maintenance

Q. Please describe Hydro Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 10, column (d), Hydro Major Maintenance expense is forecasted to be \$8.374 million in the projected test year ending April 30, 2027, and includes:

- Hydro License Initiatives (\$2,107,041). A FERC requirement, this item resulted from the relicensing of Au Sable, Manistee, and Muskegon River dams, with the main result being that the Company has annual license commitments. License commitments include some recreation, fish payments, and water quality such as upwelling systems licenses;
- Hydro annual FERC Dam Safety Requirements including Part 12 Inspections (\$1,441,220). The scope of this project is to perform the FERC-required dam safety inspections on an annual basis, and the FERC-required Part 12 inspections on each dam every five years. A similar level of expense, including modest escalation, is budgeted annually from 2026 through 2029;
- Foote Auxiliary Spillway Pilot Channel and Embankment Crest Grading Project (\$1,000,000). The scope of this project is to develop a design to raise or fill the existing auxiliary spillway pilot channel/ditch. In addition, repairs to the observed rutting and grading the right embankment crest, along with placing new fill as needed, will bring the embankment to a consistent elevation of 647.0 feet. This also includes the non-corewall section embankment widening, dependent on the results from the stability analyses.

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1 Raising the elevation of the auxiliary spillway pilot channel/ditch would
2 reduce the chance of the auxiliary spillway being activated. Repairing the
3 rutting and placing new fill on the embankments would increase the slope
4 stability factor of safety, thus reducing the chance of dam failure. This project
5 will meet FERC requirements and mitigate regulatory compliance risk.

6 The Part 12D Dam safety inspection by an independent consultant noted
7 several critical issues with the Foote Auxiliary Spillway. Flow within the
8 auxiliary spillway would initiate in the pilot channel/ditch at approximately
9 elevation 641 feet, which is 0.9 feet below the current Probable Maximum
10 Flood elevation of 641.9 feet. Additionally, rutting was observed on the right
11 embankment, and the elevation survey of the left embankment showed a
12 decrease of approximately 0.7 feet at Station 0+50 since the August 2013
13 survey. Elevations measured from Sta. 1+00 to Sta. 7+50 were below the
14 nominal embankment crest of elevation 647.0 feet, with a minimum of elevation
15 646.6 feet at Sta. 3+00.

16 Failure to comply with the Dam safety inspection recommendations could
17 result in regulatory agency action, including fines and potential loss of the
18 facility's operating license. For this project, the risk being mitigated is not the
19 risk of a probable maximum flood happening but the risk of FERC citing the
20 company for regulatory non-compliance and assessing fines accordingly. This
21 risk is significant given inspection result recommendations and operating
22 license commitments.

- 23 • Hardy Intake Tower Brick Repair (\$800,000). The scope of this project is to
24 replace all the deteriorated interior brick inside the intake tower for the full
25 height. The Hardy intake tower brickwork has been slowly deteriorating for the
26 last few years. The bricks are crumbling to the touch and there are areas with
27 significant delamination throughout the entire height of the walls (34ft). If the
28 deterioration becomes significant enough, it may impact the headgate hoists and
29 the head gates installation safety of the Operations staff;
- 30 • Tippy Spillway Chamber Inspections and Repairs (\$292,667). The project
31 scope includes performing spillway chamber inspections, engineering for
32 spillway chamber repairs and construction of repairs. The Tippy spillway
33 chambers are hollow chambers underneath the spillway. In the spillway
34 chambers, the concrete is deteriorated, rebar is exposed, and there is seepage
35 present;
- 36 • Hydro Concrete Repairs (\$243,100). The scope of this project is to make
37 necessary repairs to deteriorating concrete at all 13 River Hydro facilities. This
38 budgeted amount will allow for the performance of necessary repairs which are
39 identified after spring flows or general deterioration. The identification of large
40 concrete repairs will be considered in the annual budgeting process;

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- Five Channels Intake Deck Beam Bottom Side Repairs (\$240,000). The scope of this project is the completion of partial depth concrete repairs and cleaning and applying coatings to steel areas of degradation. This option removes the areas that have experienced degradation and thereby eliminates the ongoing debris loading hazard.

The Five Channels intake deck over the penstocks is a reinforced concrete slab, spanning upstream to downstream between intermediate concrete and steel support beams running (dam convention) left to right between penstock walls. The underside of the slab and support beams are exposed to the penstock environment. In 2018 a Condition Assessment was completed of the Five Channels Unit 1 and Unit 2 penstocks. From this assessment, it was identified that the reinforced concrete beam at the upper to lower deck transition in both Units 1 and 2 had experienced concrete spalling with reinforcement being exposed. Similarly, the steel beams supporting concrete haunches to the deck above had corrosion and spalling concrete. During the 2022 Headgate replacement project, these assessments were updated, revealing significant progression of deterioration on the Unit 2 concrete beam, with the lower layer of reinforcement completely exposed, and the second layer partially exposed. Unit 1 had similar progression, to a lesser extent. The problem associated with these observations is that the degraded/missing concrete and exposed reinforcement compromises the strength of the beam, and by extension the deck. The concrete spalling represents a debris hazard for concrete debris to the turbines below;

- Cooke Powerhouse Divider wall Pier (\$206,667). The scope of this project is to assess the condition of the divider pier between the powerhouse and the spillway and make repairs as needed to the diagonal cracking observed during the dive inspections and additional deterioration noted above water. The Part 12D independent consultant and third-party condition assessment consultant noted significant diagonal cracking in the divider pier between the powerhouse and the training wall (log chute) during the dive inspection. The underwater inspection indicated the diagonal crack is approximately 11-feet long and up to 3/8" wide. The diagonal cracking may be indicative of settlement. Other minor cracks, spalls, erosion, efflorescence, delamination, and vegetation growing in cracks are also located on the divider pier; and
- Thirty-one additional projects totaling \$2,043,000 with each individual project representing \$180,000 or less in expenses. These projects include Tippy and Cooke Log Chute Concrete Repairs, base outage funding, headgate evaluation and repairs, relief well piezometer cleaning, and condition/risk assessments.

Admin and Other Major Maintenance

Q. Please describe Admin and Other Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 12, column (d), Admin and Other Major Maintenance expense is forecasted to be \$0.150 million in the projected test year ending April 30, 2027 and includes one project: Generation control systems cyber maintenance software support. Specifically, this project provides funding for software maintenance contracts from multiple vendor systems that are not part of the DCS control vendor service contracts.

Classic 7 Major Maintenance

Q. Please describe Classic 7 (Cobb, Weadock, and Whiting units) Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 5, column (d), Classic 7 Major Maintenance expense is forecasted to be \$0.218 million in the projected test year ending April 30, 2027.

Q. Why is Consumers Energy projecting to spend \$0.218 million in Major Maintenance on the Classic 7 units in the projected test year ending April 30, 2027?

A. Although the Classic 7 units were retired in 2016, environmental regulations require the continued maintenance of the on-site ash ponds, which includes Cobb landfill and ash pond O&M, Weadock landfill license and inspections, and Whiting ash pond post-closure care.

KARN AND CAMPBELL RETENTION AND SEPARATION PLAN EXPENSE

Q. What are the projected costs for the Company's Karn and Campbell Retention and Separation plans?

A. As reflected on Exhibit A-43 (RTB-4), page 1, line 5, the Company incurred actual expense of \$8.626 million in 2024, and is projecting expense of \$5.182 million in the 16-month projected bridge period ending April 30, 2026. The actual 2024 expense of \$8.626 million is based upon expense of \$0.495 million for Karn and \$8.626 million for Campbell. The 16-month projected bridge period expense of \$5.182 million is entirely based upon expense of \$5.182 million for Campbell. There is no projected test year expense.

Q. Is the Company requesting O&M recovery of the \$5.182 million projected amount for the projected bridge period?

A. No. The Company is not requesting approval of this projected amount in Generation O&M expense. The Company received approval in Electric Rate Case No. U-20697, to defer the recovery of the Karn Retention and Separation O&M amounts for 2021 through 2023. The Company received approval to defer the recovery of the Campbell retention and separation amounts in the Settlement Agreement in its 2021 IRP. As such, the projected amounts for 2024 through the projected bridge period ending April 30, 2026 are not included in the Total O&M amounts on Exhibit A-43 (RTB-4), page 1, line 6, columns (b), (c) and (d). Company witness Daly supports regulatory asset treatment of these expenses in his direct testimony.

Q. Please describe the Karn retention and separation plan.

A. The Karn retention and separation plan was a people strategy that the Company had implemented to ensure that it could retain the necessary qualified employees to operate Karn Units 1 and 2 through their retirement date in May 2023, as well as during the cold

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1 and dark time period following retirement. The cold and dark condition refers to the period
2 following plant retirement and prior to plant decommissioning. During this period, limited
3 environmental remediation and perhaps partial demolition is performed. The facility may
4 be physically secured with fencing and other measures to prevent vandalism or theft so as
5 to limit liability risks. On June 7, 2019, the MPSC approved the Company's 2018 IRP
6 Settlement Agreement, which included the retirement of Karn Units 1 and 2 in May 2023.
7 The Company's IRP included detailed support of the Company's need to implement a
8 retention and separation plan to ensure that it could operate the plants safely and reliably
9 through their retirement date.

10 **Q. What is the purpose of the retention component of the Company's plan?**

11 A. The Company had a strong interest in keeping qualified employees working at Karn Units 1
12 and 2 through their retirement date to ensure safe and reliable operations. The retention
13 component allowed the Company to retain employees that may seek employment at other
14 Company locations or outside of the Company. The Company's ability to hire new
15 employees at Karn Units 1 and 2 became increasingly difficult given the short remaining
16 lifespan of the units and, to the extent that the Company had the ability to hire new
17 employees, the training time necessary for any new hires provided a significant challenge
18 to operating the units both safely and reliably. The retention component utilized the best
19 practices that the Company employed in retiring the Classic 7.

20 **Q. What is the purpose of the separation component of the Company's plan?**

21 A. Now that Karn Units 1 and 2 are retired, the Company is following the terms of the
22 collective bargaining agreement for OM&C employees represented by the Utility Workers
23 Union of America ("UWUA"), and the terms of the employee handbook policy and

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1 separation plan for non-represented exempt and non-exempt employees. The structure and
2 amount of the severance offers varies based on employee salary and classification due to
3 differences in the terms of the separation plan covering non-represented employees and the
4 bargaining agreement for UWUA-represented employees. In the event that exempt or
5 non-exempt employees cannot find placement within the Company within 60 miles of their
6 current location, they will be offered involuntary severance in accordance with the terms
7 of the Company's Salaried Separation Plan. The Company's Working Agreement with the
8 UWUA governs separation for OM&C employees who elect to leave the Company rather
9 than accept a new position as well as relocation expenses if they accept a position more
10 than 60 miles away from their current location.

11 **Q. What are the benefit types associated with the Karn retention and separation plan?**

12 A. The Karn retention and separation plan includes three benefit types: retention benefits,
13 severance benefits, and relocation and moving costs.

14 **Q. Please describe the retention benefits associated with the Karn retention and**
15 **separation plan.**

16 A. The retention benefits associated with the Karn retention and separation plan include three
17 payment components: a signing incentive, annual incentives, and a final retention
18 incentive.

19 Employees received a signing incentive equal to 15% of their base pay if they
20 signed a retention agreement in October 2019. By signing the retention agreement, the
21 employee agreed to forfeit their transfer rights under the current working agreement (for
22 union employees) or under Company policy (for exempt and non-exempt employees). The
23 employee had to stay at Karn until October 31, 2020 to receive the payment; if the

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1 employee stayed until that date, the incentive was paid out to the employee within 30 days.

2 If the employee separated from the Company before October 31, 2020, the employee
3 forfeited the signing incentive.

4 Employees received an annual incentive which graduated from 20% to 30% of their
5 base pay for service each November in years 2019, 2020, and 2021, for staying at Karn and
6 rendering service for the next 12 months. The employee had to stay at Karn until
7 October 31 of the following year to receive the payment; if the employee stayed until that
8 date, the incentive was paid out to the employee within 30 days. If the employee separated
9 from the Company before October 31 of the next year, the employee forfeited the annual
10 incentive. Eligible employees received their first annual incentive payment in November
11 2020, a second payment in November 2021, and a third payment in November 2022.

12 Employees received their final retention incentive equal to 60% of their base pay
13 following plant retirement if the employee was still at Karn. The payment was intended to
14 incentivize employees to stay until the plant went cold and dark and compensate employees
15 for the service they rendered for the eight months (November 2022 through June 2023)
16 prior to the payment.

17 **Q. Please describe the severance benefits associated with the Karn retention and**
18 **separation plan.**

19 **A.** The severance benefits associated with the Karn retention and separation plan includes
20 initial recognition of a severance benefit to be paid, recognition of additional severance
21 earned (one week of pay per year of service), and recognition of the accretion of a final
22 severance benefit.

1 **Q. Why did the Company anticipate the need to make severance payments associated**
2 **with the retirement of Karn Units 1 and 2?**

3 A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016,
4 all Company employees that desired to continue employment with the Company were able
5 to do so. However, the Company is also aware of the fact that it has fewer Company
6 locations (11 within 60 miles of the Karn site) to which employees could relocate, than it
7 did in 2016. As such, the Company anticipated the need to make severance payments to
8 those employees that could not find placement. As I previously stated, the Company is
9 following the terms of the collective bargaining agreement for OM&C employees
10 represented by the UWUA, and the terms of the employee handbook policy and separation
11 plan for non-represented exempt and non-exempt employees.

12 **Q. Please explain the relevant details of the collective bargaining agreement for OM&C**
13 **employees.**

14 A. The collective bargaining agreement for OM&C employees, in Article VII, Section 17, and
15 the Generation Operations Coal Closing Agreement provide that employees will be placed
16 in either a corresponding position, or if none exists, in a vacant position he/she is qualified
17 to perform within 60 miles of his/her current headquarters. Per Article XVII of the
18 collective bargaining agreement, employees who are released due to lack of work, and are
19 not placed as described above, are provided a separation allowance consisting of straight
20 time pay for five regular workdays for each year of continuous service with the
21 Company. Due to the lack of Company locations within 60 miles of Karn Units 1 and 2,
22 as described above, it was anticipated that some employees would be eligible for a
23 separation allowance.

1 **Q. Please describe the Campbell retention plan.**

2 A. The Campbell retention plan is a people strategy that the Company proposed in its 2021
3 IRP. As previously discussed, the Company's 2021 IRP PCA reflects the retirement of
4 Campbell Units 1, 2, and 3 on May 31, 2025. This retention plan was proposed in order to
5 retain employees through the closure of the three Campbell units. This strategy is
6 necessary to ensure that the Company can operate the Campbell units safely and reliably
7 through their retirement date. This incentive program is the same program that is currently
8 in place for employees at the Karn site.

9 **Q. What is the purpose of the retention component of the Company's plan?**

10 A. For similar reasons described in the Karn retention plan, the Company had a strong interest
11 in keeping qualified employees working at the Campbell site through their retirement date
12 to ensure safe and reliable operations. The retention component will allow the Company
13 to retain employees that may seek employment at other Company locations or outside of
14 the Company. Similar to the situation at the Karn site, it was increasingly difficult to hire
15 new employees at the Campbell site given the short remaining lifespan of the units and, to
16 the extent that the Company has the ability to hire new employees, the training time
17 necessary for any new hires provided a significant challenge to operating the three units
18 both safely and reliably.

19 **Q. What is the purpose of the separation component of the Company's plan?**

20 A. After the Campbell units are retired, the Company is following the terms of the collective
21 bargaining agreement for OM&C employees represented by the UWUA, and the terms of
22 the employee handbook policy and separation plan for non-represented exempt and
23 non-exempt employees. The structure and amount of the severance offers will vary

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1 based on employee salary and classification due to differences in the terms of the
2 separation plan covering non-represented employees and the bargaining agreement
3 for UWUA-represented employees. In the event that exempt or non-exempt employees
4 cannot find placement within the Company within 60 miles from their current location,
5 they will be offered involuntary severance in accordance with the terms of the Company's
6 Salaried Separation Plan. The Company's Working Agreement with the UWUA governs
7 separation for OM&C employees who elect to leave the Company rather than accept a new
8 position as well as relocation expenses if they accept a position more than 60 miles away
9 from their current location.

10 **Q. What are the benefit types associated with the Campbell retention plan?**

11 A. Similar to the Karn retention and separation plan, the Campbell retention plan includes
12 three benefit types: retention benefits, severance benefits, and relocation and moving costs.

13 **Q. Please describe the retention benefits associated with the Campbell retention plan.**

14 A. The retention benefits associated with the Campbell retention plan include three payment
15 components: a signing incentive, periodic incentives, and a final retention incentive. The
16 timeline for retention benefits reflects approval of the Settlement Agreement in the
17 Company's 2021 IRP in June 2022.

18 Employees received a signing incentive equal to 15% of their base pay if they
19 signed a retention agreement in July 2022. By signing the retention agreement, the
20 employee agreed to forfeit their transfer rights under the current working agreement (for
21 union employees) or under Company policy (for exempt and non-exempt employees). The
22 employee had to stay at Campbell until October 31, 2022 to receive the payment; if the
23 employee stayed until that date, the incentive was paid out to the employee within 30 days.

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1 If the employee separated from the Company before October 31, 2022, the employee
2 forfeited the signing incentive.

3 Employees received a periodic incentive which graduates from 20% to 30% of their
4 base pay for service each November in years 2022, 2023, and 2024, for staying at Campbell
5 and rendering service for a certain period. Specifically, for service provided July 2022
6 through October 2022, employees received 20% of their base pay. For service provided
7 November 2022 through October 2023, employees received 25% of their base pay. For
8 service provided November 2023 through October 2024, employees received 30% of their
9 base pay. The employee must stay at Campbell until October 31 of the given year to receive
10 the payment; if the employee stays until that date, the incentive was/will be paid out to the
11 employee within 30 days. If the employee separates from the Company before October 31
12 of the given year, the employee forfeits the annual incentive.

13 Employees receive a final retention incentive equal to 60% of their base pay on or
14 about October 31, 2025, if the employee is still at Campbell. The payment is intended to
15 incentivize employees to stay until the plant goes cold and dark and compensate employees
16 for the service they rendered for the 12 months prior to the payment.

17 **Q. Please describe the severance benefits associated with the Campbell retention plan.**

18 A. The severance benefits associated with the Campbell retention plan include initial
19 recognition of a severance benefit to be paid, recognition of additional severance earned
20 (one week of pay per year of service), and recognition of the accretion of a final severance
21 benefit.

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1 **Q. Why does the Company anticipate the need to make severance payments associated**
2 **with the retirement of Campbell Units 1, 2, and 3?**

3 A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016,
4 all Company employees who desired to continue employment with the Company were able
5 to do so. However, the Company is also aware of the fact that it has fewer Company
6 locations (seven within 60 miles of the Campbell site) to which employees can relocate,
7 than it did in 2016. In addition, the Company also retired two of the Karn generating units
8 in 2023, thereby further reducing the available positions. As such, the Company has
9 anticipated the need to make severance payments to those employees who cannot find
10 placement. As I previously stated, the Company is following the terms of the collective
11 bargaining agreement for OM&C employees represented by the UWUA, and the terms of
12 the employee handbook policy and separation plan for non-represented exempt and
13 non-exempt employees, as previously discussed for the Karn retention and separation plan.

14 **Q. Does this conclude your direct testimony?**

15 A. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

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1 **Q. Please state your name and business address.**

2 A. My name is Eugène M.J.A. Breuring, and my business address is One Energy Plaza,
3 Jackson, Michigan 49201.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
6 as a Principal Sales Forecasting Analyst in Financial Planning & Analysis.

7 **Q. Please describe your qualifications.**

8 A. In 1992, I graduated from Grand Valley State University with a Bachelor of Business
9 Administration in Accounting. In 1996, I graduated from Thunderbird School of Global
10 Management with a Master of Business Administration in International Management.
11 I have also attended trade-specific conferences and seminars related to Michigan and
12 United States economies, Michigan economic forecasts, as well as regression modeling.

13 Prior to joining Consumers Energy in 2013, I worked at the Kellogg Company,
14 Tecumseh Products Company, and Stryker Corporation, mostly in a financial planning,
15 budgeting, and forecasting capacity. In January 2013, I accepted the position of Senior
16 Rate Analyst II. In 2020, I was promoted to Senior Analyst III, and again in 2023 to
17 Principal Sales Forecasting Analyst, which is my current position at Consumers Energy.
18 In this capacity, I am responsible for preparing the Company’s official electric deliveries
19 and customer forecasts, sponsoring the deliveries and customer forecast testimony and
20 exhibits, industry research, and various economic studies. Also, I am responsible for
21 creating the Company’s revenue forecast related to the electric business.

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1 **Q. Have you sponsored testimony in any previous cases before the Michigan Public**
2 **Service Commission (“MPSC” or the “Commission”)?**

3 A. Yes, I have presented the Company’s electric business sales and revenues forecasts in the
4 following cases:

5	U-17771	2016 – 2017 Energy Optimization Plan;
6	U-17990	General Electric Rate Case;
7	U-18142	2017 Power Supply Cost Recovery (“PSCR”) Plan;
8	U-18231	2017 Biennial Renewable Energy Plan;
9	U-18261	Amended Energy Optimization Plan;
10	U-18322	General Electric Rate Case;
11	U-18402	2018 PSCR Plan;
12	U-20134	General Electric Rate Case;
13	U-20165	2018 Integrated Resource Plan (“IRP”);
14	U-20219	2019 PSCR Plan;
15	U-20372	2019 Energy Waste Reduction (“EWR”) Electric and Gas Plan;
16	U-20525	2020 PSCR Plan;
17	U-20697	General Electric Rate Case;
18	U-20802	2021 PSCR Plan;
19	U-20875	2022-2025 EWR Plan;
20	U-20963	General Electric Rate Case;
21	U-21048	2022 PSCR Plan;
22	U-21090	2021 IRP;
23	U-21257	2023 PSCR Plan;

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U-21321 2024-2025 EWR Plan;
U-21389 General Electric Rate Case;
U-21423 2024 PSCR Plan;
U-21585 General Electric Rate Case;
U-21592 2025 PSCR Plan;
U-21680 2025 EWR Plan; and
U-21816 Amended RE Plan.

Furthermore, I have been involved in preparing the forecasts sponsored by other Company witnesses in prior cases before the MPSC.

Q. Please explain the purpose of your direct testimony in this proceeding.

A. The purpose of my direct testimony is to present the Company's electric revenues, deliveries, generation requirements, and peak demands for the split-test year May 2026 – April 2027.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am providing the following exhibits:

Exhibit A-5 (EMB-1)	Schedule E-1	Annual Service Area Calendar Sales by Major Customer Classes and System Output – 5-Year Historical;
Exhibit A-15 (EMB-2)	Schedule E-1	Annual Service Area Calendar Sales by Major Customer Classes and System Output – 5-Year Projected;
Exhibit A-15 (EMB-3)	Schedule E-2	Test Year Total Company Electric Revenues & Deliveries;
Exhibit A-15 (EMB-4)	Schedule E-3	Electric Deliveries & Customer Counts by Rate Category;
Exhibit A-15 (EMB-5)	Schedule E-4	Calculation of Annual System Load Factor; and

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Exhibit A-52 (EMB-6)

Estimated Electric Rate Case PSCR
Factor.

Q. Were these exhibits prepared by you or under your direct supervision?

A. Yes.

SECTION I. FORECASTING METHODOLOGY

Q. What is forecasting?

A. Forecasting is predicting the future values of data. For purposes of this direct testimony, the Company will forecast electric deliveries and peak demand for the Company's electric service territory.

Q. Are there different types of analyses used in preparing forecasts?

A. Yes.

Q. What type of analysis was utilized for forecasting electric deliveries and peak demand for the Company's electric service territory?

A. Statistical modeling, or a regression analysis, was used to forecast electric deliveries and peak demand for the Company's electric service territory.

Q. Please briefly describe the process used to prepare the electric deliveries and peak demand forecasts.

A. The electric deliveries and peak demand forecasts are prepared using a combination of econometric and end-use techniques.

Q. What process is involved in developing the electric deliveries forecast?

A. Typically, a six-step process is used in developing the electric deliveries forecast. The first step in the process is gathering the class-level historical monthly electric delivery, monthly customer counts, monthly number of billing days, monthly binaries to account for seasonal variation, and daily temperature information. Most observations are entered directly into

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1 the modeling framework as dependent and explanatory variables. The daily temperature
2 information, however, is transformed to monthly heating degree days (“HDD”) and cooling
3 degree days (“CDD”) variables prior to entering the modeling framework. The second step
4 is importing the economic and demographic variables from S&P Global (formerly, IHS
5 Markit) into the sales modeling framework. These variables cover historical data going
6 back to 2001, the start of the time horizon within the regression modeling process, as well
7 as projections to the test year. The third step is importing electric use forecasts for
8 wholesale, electric vehicles, polycrystalline production, Distributed Generation (“DG”),
9 and energy savings from the Company’s EWR programs. These forecasts are exogenous
10 to the modeling framework and were either adopted by the Commission in prior electric
11 rate cases, reflect current industry expectations, or are based on end-use analyses. The
12 fourth step is reviewing the imported observations to identify data issues before running
13 the econometric models. In situations when erroneous data is observed, it is either
14 corrected where possible or removed from the models. The fifth step is executing the
15 regression functions and reviewing the corresponding statistical metrics. The final step in
16 the sales forecasting process is to combine the regression forecasts with the external
17 forecasts imported in step three.

18 **Q. What is the process involved in developing the electric peak demand forecast?**

19 A. The peak demand forecast process is like that of the electric delivery forecast. The first
20 step in the peak demand forecast is importing the Company’s monthly system peak
21 demands, corresponding minimum and maximum daily temperature, forecasted base
22 electric deliveries, seasonal binaries, and number of customers into the demand modeling
23 framework. An average of the minimum and maximum temperatures is used to develop

1 the peak CDD and HDD variables before these variables are imported into the model
2 framework. The second step is reviewing the imported observations to identify data issues
3 before executing the peak demand econometric model. The third step is regressing the
4 observed peak demands against the seasonal binary, degree day, and forecasted base
5 electric sales.

6 The final step in the peak demand forecasting process is combining the results of
7 the econometric model with the Company's projected peak demand adjustments, which
8 consists of the following: (1) EWR; (2) Dynamic Peak Pricing ("DPP") programs;
9 (3) Conservation Voltage Reduction ("CVR"); and (4) Residential Summer On-Peak rate
10 ("RSP").

11 **Q. In utilizing the regression models, what evaluation process is followed to ensure that**
12 **the models' results are satisfactory?**

13 A. Regression modeling is used to develop the electric deliveries and customer count forecast
14 models based on weather and economic variables. Each model is selected based on its
15 ability to properly explain variation in historical data – i.e., how well it fits the data – along
16 with the statistical significance of the model coefficients. Particularly, regression model
17 performance is evaluated based on the adjusted coefficient of multiple determination
18 (" R_a^2 ") and Mean Absolute Percent Error ("MAPE").

19 **Q. Please explain the use of R_a^2 and MAPE.**

20 A. Both statistical tests are used to evaluate how well the models fit the historical data and
21 provide a good indication of how well the models will perform in the forecast period. The
22 R_a^2 measures the ability of the models to explain variations in the historical data. An R_a^2 of
23 unity suggests that a model explains all the variations in the data whereas an R_a^2 of zero

1 suggests it explains none of the variations. For example, if regression models have R_a^2
2 values above 0.9, this suggests that at least 90% of the variation in the data is explained by
3 the models. In most cases, the models used in the Company's forecasting process have
4 values between 0.90 and 0.97. In addition, to gauge overall model performance, the MAPE
5 values are considered. Essentially, MAPE is used to measure the model errors in which
6 smaller values suggest better model performance. MAPE values of less than 3% are
7 generally considered ideal, although higher values may also be deemed acceptable based
8 on other considerations, such as the R_a^2 . The regression models used in the Company's
9 forecasting process generally have MAPE values between 0.2% and 2.1%.

10 **Q. Please explain the criteria used when considering the t-statistics and p-values**
11 **associated with the model coefficients.**

12 A. Regression analysis is used to develop models that minimize the variance between the
13 actual data and estimates from the models based on the relationship between dependent
14 and independent variables. A numerical coefficient (" β ") is estimated for each
15 independent variable in the model and represents the best linear unbiased estimate for that
16 variable's contribution toward explaining the dependent variable. The t-statistics and
17 p-values are used to gauge the relevance of each independent variable in the model. The
18 t-statistic and p-values measure the statistical significance of including a particular
19 independent variable based on a probability distribution. A t-statistic above two and
20 p-value below 5% for a particular β suggests the independent variable is statistically
21 significant and is appropriate to include in the regression model. Independent variables
22 with t-statistics below two and p-values above 5% suggest the variable should be excluded
23 from the model since it does little to explain the dependent variable. In addition, the

direction (positive or negative coefficient sign) and magnitude of each coefficient are also considered when determining to include or exclude variables from the models. The models' independent variable t-statistics and p-values are within the statistically significant ranges described above and are, therefore, considered relevant.

Q. What software is used to create these regression models for the energy, demand, and customer count projections? And why?

A. For at least the last 15 years, the Company has utilized MetrixND for its regression modeling. MetrixND is a software package that is licensed by Itron, Ltd., a global technology company that provides technology and professional services to utilities to aid in their sales forecasting needs. Furthermore, MetrixND is considered an industry standard, as more than 150 utilities, Independent System Operators, municipals, cooperatives and other energy service providers use Itron's MetrixND.¹

SECTION II. KEY ELECTRIC DELIVERY AND DEMAND VARIABLES

Q. What are the key variables that affect the electric deliveries and demand forecasts?

A. The key variables affecting the forecasts are weather, the economy, and demographics, as well as variables related to EWR, DG, Electric Vehicles ("EVs"), and COVID-19, a variable to capture the impact of the COVID-19 pandemic.

Q. Please describe the impact of weather on the forecasting process and the assumptions you made regarding weather variables in the forecast.

A. Weather is the primary variable used in the forecasting models to capture the seasonal variation in deliveries and demand across the year. This is accomplished using a 15-year average of Heating Degree Days-60 ("HDD60") and Cooling Degree Days-60 ("CDD60")

¹ <https://na.itron.com/o/commerce-media/accounts/-1/attachments/3828543>.

1 in the econometric models. The HDD60 variable captures historical temperatures warmer
2 than 60 degrees Fahrenheit. The CDD60 variable captures historical temperatures cooler
3 than 60 degrees Fahrenheit.

4 **Q. What are econometrics or econometric techniques?**

5 A. These are quantitative economic statistical techniques or tools that model the economy
6 using mathematical and statistical relationships. A basic tool for econometrics is the
7 regression model, as discussed elsewhere in my testimony.

8 **Q. Please describe the impact of the economy on the forecasting process and the**
9 **assumptions you made regarding these variables in the forecast.**

10 A. The Company uses economic indicators to capture the growth expectations related to
11 increased economic activity in its service territory. Primarily, this includes employment
12 and industrial production forecasts provided by S&P Global, a leading publishing company
13 that provides industry-specific data and analyses.

14 **Q. Please describe the impact of demographics on the forecasting process.**

15 A. Population projections are used in the development of the long-term customer forecast. In
16 particular, the forecast of commercial customers is derived from the county-level
17 population projections provided by S&P Global.

18 **SECTION III. TEST YEAR ELECTRIC REVENUES**

19 **Q. Please describe Exhibit A-15 (EMB-3), Schedule E-2.**

20 A. Exhibit A-15 (EMB-3), Schedule E-2, is a single-page exhibit that summarizes the
21 component differences between the 2024 historical revenues and deliveries and the
22 forecasted test year revenues and deliveries used in this case.

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1 **Q. Please explain the Weather-Normalization column, column (f), in Exhibit A-15**
2 **(EMB-3), Schedule E-2.**

3 A. Exhibit A-15 (EMB-3), Schedule E-2, represents a “walk” from the 2024 historical year to
4 the projected test year. The historical year represents actual revenues and deliveries, which
5 are not weather-normalized. Since the Company’s projections are weather-normalized,
6 column (f) represents the 2024 impact of weather-normalizing the historical actuals.

7 **Q. Please explain the Pro Forma column, column (h), in Exhibit A-15 (EMB-3),**
8 **Schedule E-2.**

9 A. The Pro Forma column in this exhibit represents the difference in revenues due to the
10 difference in rates between the historical year 2024 and the projected test year. 2024
11 revenues were based on customer rates established by the Commission’s March 1, 2024,
12 Order in Case No. U-21389 (“Case No. U-21389 Order”), while the test year revenues are
13 projected revenues based on the rates established by the Commission’s March 21, 2025
14 Order in Case No. U-21585 (“Case No. U-21585 Order”).

15 **Q. Please explain the Long-Term Industrial Load Retention Rate (“LTILRR”) and**
16 **Large Economic Development Rate (“LEDR”) adjustment, shown in column (e), to**
17 **deliveries (MWh) and revenues in Exhibit A-15 (EMB-3), Schedule E-2.**

18 A. The LTILRR and LEDR are specialized industrial rates. The LTILRR was approved by
19 the Commission in its Case No. U-20697 Order to allow customized electric rates
20 (LTILRR) for customers meeting certain criteria. The LEDR was approved by the
21 Commission in its Case No. U-21160 Order. As such, the Company has excluded revenues
22 and deliveries of certain large industrial customers that receive service under the LTILRR
23 and LEDR from base tariff revenues, as well as deliveries in the test year. Instead, these

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1 projected test year revenues are reflected in the Miscellaneous Revenues line in
2 Exhibit A-15 (EMB-3), Schedule E-2, column (e), line 24. Company witness Laura M.
3 Connolly supports the details behind these LTILRR/LEDR projected revenues and
4 deliveries.

5 **Q. Please explain the credit revenues that are included in the test year projections as they**
6 **relate to the Residential Senior Citizen (“RSC”) and Residential Income-Assistance**
7 **(“RIA”) provisions.**

8 A. The average test year customer count projections for the RSC and RIA provisions are
9 380,928 and 63,282, respectively. In the test year, these projected customer counts
10 generate revenue credits of \$18.3 million (380,928 customers x \$4 credit x 12 months) for
11 the RSC provision and \$7.6 million for the RIA provision (63,282 RIA customers x
12 \$8 credit x 12 months = \$6.1 million plus 4,200 Low-Income Assistance Credit (“LIAC”)
13 customers x \$30 credit x 12 months = \$1.5 million). Included in the RIA credit revenues
14 is a \$30/meter LIAC for 4,200 low-income customers, as approved by the Commission’s
15 Case No. U-20697 Order.

16 The associating reduction in base tariff revenues is embedded in Exhibit A-15
17 (EMB-3), Schedule E-2, column (j), line 1.

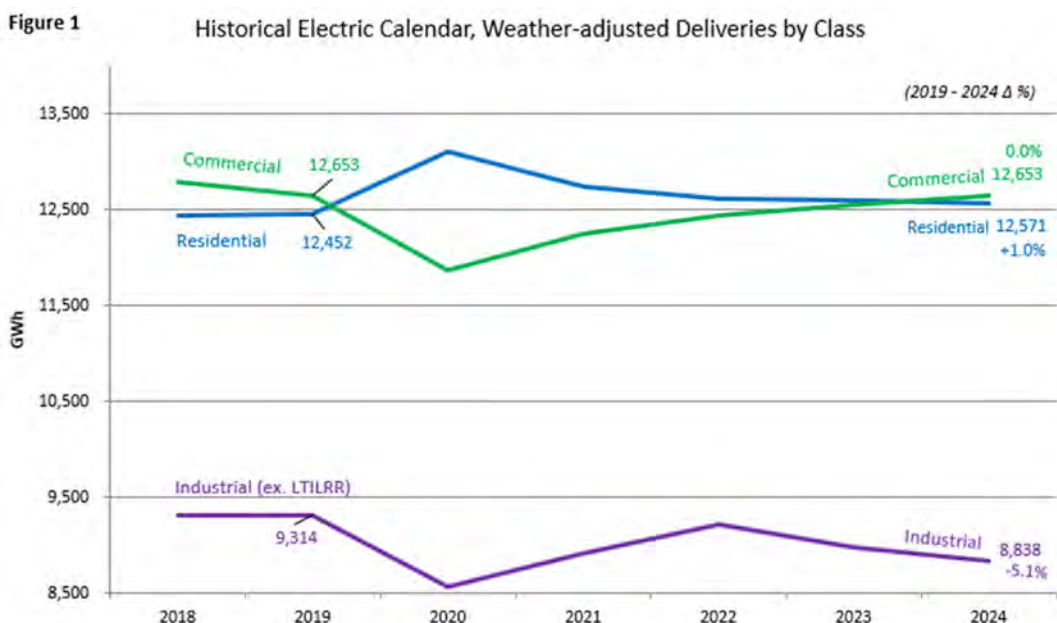
SECTION IV. HISTORICAL AND FORECASTED ELECTRIC DELIVERIES

Q. In the Order of Case No. U-21585, the Commission directed the Company to provide both historical and forecasted sales on both a cycle-billed and calendar basis and provide the 60-months of most recent actual historical, weather-normalized historical, and projected sales in the same level of granularity. Has this been provided?

A. Yes. In Part III, attachments 014, 015, and 016, both historical and forecasted data are shown by calendar and cycle-billed, by class and on a monthly basis for 60 months.

Q. Please explain the Company's historical levels of electric deliveries for the period from 2019 (pre-pandemic) to the historical year 2024.

A. In the years since 2019 (pre-pandemic), weather-normalized electric deliveries have remained virtually flat at a -0.1% decrease versus 2024 (the historical year), with the industrial class changing -5.1%, and the commercial class changing 0.0%. The residential class showed an increase of 1.0% during this period. These changes are graphically depicted in Figure 1.



1 **Q. What is the cause of the sudden Residential increase and Commercial/Industrial**
2 **(“C&I”) decrease of the 2020 weather-normalized deliveries, as shown in Figure 1?**

3 A. Following 2019, the Company’s deliveries were impacted by the COVID-19 virus and the
4 resulting pandemic. In 2020, the pandemic caused significant customer behavioral
5 changes, such as an increase in remote working and temporary cessations or reductions in
6 in-person operations for some C&I customers.

7 **Q. How did COVID-19 impact the different customer classes?**

8 A. COVID-19 and the ensuing pandemic had an inverse effect on the Company’s residential
9 and C&I customer classes. In 2020, the residential deliveries increased 5.2% over 2019 on
10 a weather-adjusted basis. Conversely, weather-adjusted C&I (excl. LTILRR) deliveries
11 decreased by 6.2% and 8.0%, respectively.

12 **Q. Have the customer classes returned to their pre-pandemic levels by the historical year**
13 **2023?**

14 A. Generally, each customer class has returned to a “post-pandemic” trend. Meaning, these
15 classes have mostly recovered from the significant impact the pandemic had on their
16 individual trends (residential class up, commercial flat, and industrial class down). When
17 looking at Figure 1 above, the residential class remains 1% above pre-pandemic levels
18 (after its steep increase of 5.2% in 2020), which can be attributed to the fact that the
19 “working remotely” paradigm has shifted to where some employees are still working
20 remotely part of the time. The C&I classes remain near or below pre-pandemic levels by
21 0.0% and 5.1%, respectively (after respective declines of 6.2% and 8.0% in 2020).

1 **Q. What are the electric delivery expectations for the test year used in this case?**

2 A. Test year deliveries are projected at 38,662 GWh, as shown in Exhibit A-15 (EMB-2),
3 Schedule E-1, which is an approximate two-year compound annual growth rate (“CAGR”)
4 of +2.5% over the weather-normalized historical year 2024 of 36,776 GWh, as shown in
5 Exhibit A-5 (EMB-1), Schedule E-1, page 2. However, 3.6% of this growth is attributable
6 to LTILRR/LED. Excluding LTILRR/LED, the two-year CAGR is -1.1%.

7 **Q. Please explain Exhibit A-15 (EMB-4), Schedule E-3.**

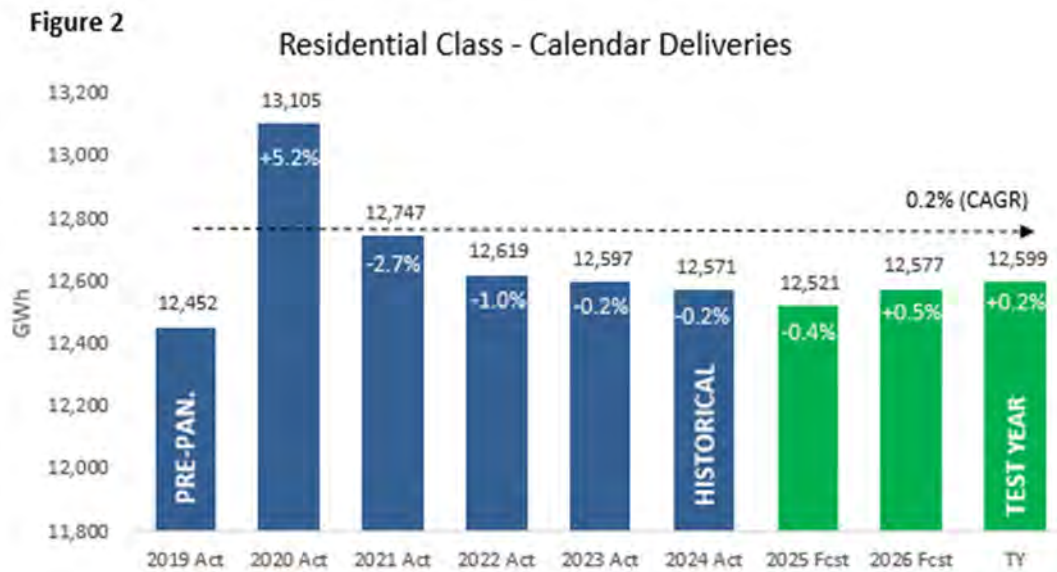
8 A. Exhibit A-15 (EMB-4), Schedule E-3, is a one-page exhibit that shows annual deliveries
9 and customer counts by rate category from the historical year to the test year. The historical
10 year (2024) figures are aligned with numbers as reported to the MPSC (Form P-521) and
11 the deliveries are not weather-adjusted.

12 **Q. Please explain the significant decrease in deliveries from the historical year to the test**
13 **year in this exhibit.**

14 A. The main driver of change in deliveries between the historical year and the test year is
15 related to LTILRR volumes (represented in Primary Demand GPD), which are excluded in
16 the test year, but have not been removed from the historical period. Also excluded from
17 the test year are deliveries related to Grand Rapids (“GR”) Streetlighting, which is
18 considered non-jurisdictional. Same as the last rate case, GR test year volumes and
19 revenues are categorized as miscellaneous. Its deliveries (MWh) are excluded from the
20 test year, while its revenues are included in miscellaneous revenues (see Exhibit A-15
21 (“EMB-3”), Schedule E-2, column (d), line 24. Finally, the single wholesale customer
22 (non-jurisdictional) has ceased its contract with the Company as of the end of 2024.
23 Therefore, no wholesale deliveries are shown in the test year.

Q. What do the historical and projected deliveries look like in the residential customer class?

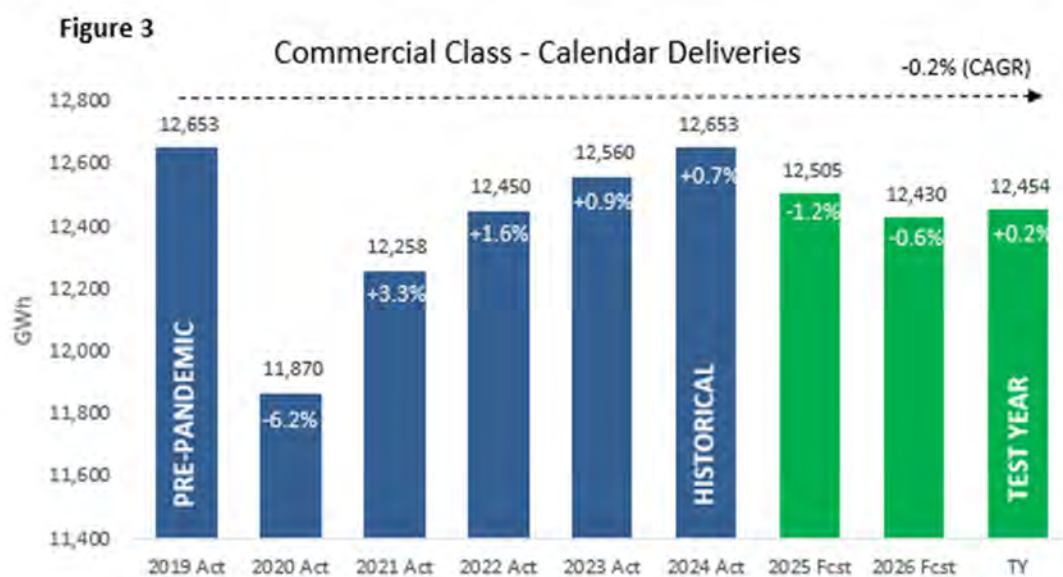
A. The residential customer class is projected to grow at a 0.2% CAGR from 2019 (pre-pandemic) to the test year. As can be seen from Figure 2 below, the residential class increased significantly in 2020 due to, among other things, many people working from home (+5.2%, year-over-year). 2021 was seen as a correction with deliveries reducing by 2.7% as some workers returned to in-person work at an office location. As a result of this reversion to pre-pandemic behavior regarding work locations, residential deliveries are projected to continue to level out toward the test year.



Q. What do the historical and projected deliveries look like in the commercial customer class?

A. The commercial customer class is projected to recede by a -0.2% CAGR from 2019 (pre-pandemic) to the test year. As can be seen from Figure 3, the commercial class decreased significantly in 2020 due to the negative impact the pandemic had on retail, schools, restaurants, and other commercial customers (-6.2%, year-over-year). 2021

marked an improvement for these commercial sectors, which is reflected by the 3.3% year-over-year increase in deliveries. Commercial deliveries are projected to level out toward the test year, though total deliveries in the test year are still below the pre-pandemic year of 2019 by a -0.2% CAGR.



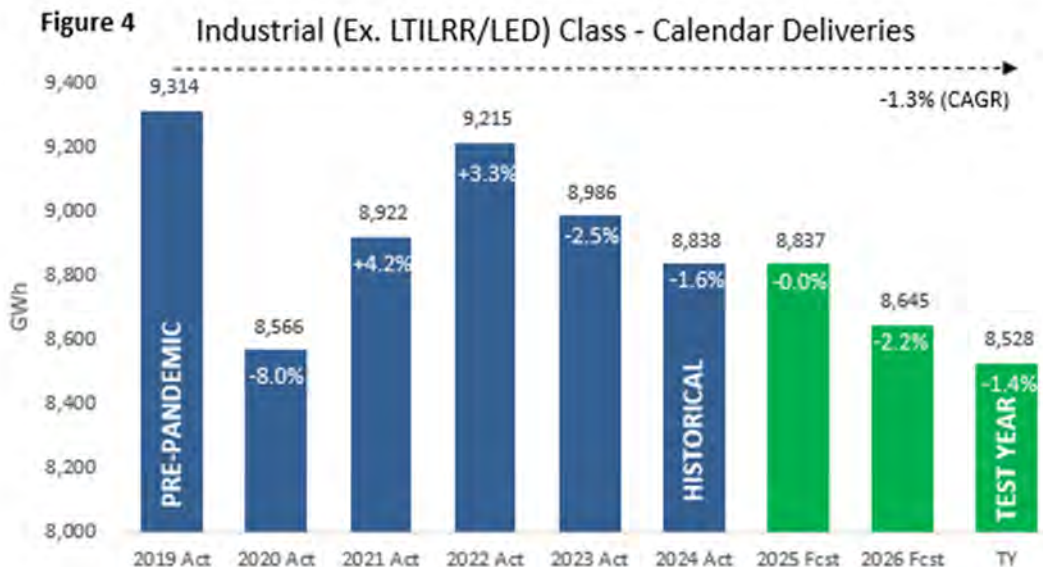
Q. What causes the reduction in projected deliveries in the commercial class?

A. The majority of the reduction is due to increased levels of EWR from the historical year to the test year. Please refer to page 18 for more details around EWR savings by customer class.

Q. What do the historical and projected deliveries look like in the industrial customer class?

A. The industrial class is projected to recede by a -1.3% CAGR from pre-pandemic to the test year. Initially, in 2020, the industrial class was impacted more drastically than the other classes, as the class decreased by 8.0% year-over-year. See Figure 4. However, two years

1 later, in 2022, this class regained most of lost sales since the pandemic. From the historical
2 year to the test year, EWR pressures push the deliveries down.



3 **Q. Does the test year delivery forecast anticipate an increase in EVs in the Company's**
4 **service territory?**

5 A. Yes, the Company is expecting the number of EVs in its service territory to grow from
6 39,950 in 2024 to an estimated 122,989 EVs by the test year, which is a 68% CAGR. These
7 122,989 EVs will add incremental annual electric load of approximately 480 GWh.

8 **Q. Is the increased load due to EVs concentrated only around the residential customer**
9 **class?**

10 A. No, of the total anticipated incremental EV load of 480 GWh in the test year, 314 GWh
11 (65%) is expected to be residential load. The other 166 GWh (35%) is allocated to the
12 business sector.

13 More details related to EVs is covered by Company witness Jeffrey A. Myrom.

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1 **Q. Does the test year delivery forecast include any impact due to DG?**

2 A. Yes. DG remains a relatively small piece of the total deliveries in the test year. DG is
3 expected to increase at a faster growth rate than historical levels. In 2025, DG is expected
4 to reduce residential deliveries by 37 GWh, or 0.30% of total residential load. For the test
5 year, DG is projected to increase to 44 GWh, or 0.35% of total residential load.

6 **Q. To what extent has the Company reflected future EWR in the electric deliveries**
7 **forecast you are sponsoring in this case?**

8 A. The Company was required under the 2008 Energy Law, Public Act 295, to help its electric
9 customers reduce their energy usage by at least 1% per year. In 2016, State lawmakers
10 reinforced the use of demand-side resources, such as EWR, by amending the law to
11 encourage utilities to expand the use of demand-side resources beyond the mandated floors.
12 The Governor signed the 2016 Energy Laws, Public Acts 341 and 342, on December 21,
13 2016. Most recently, in 2023, the Michigan Legislature and Governor again amended the
14 law to include a 1.5% EWR mandate for electric utilities beginning in 2026 and a 2% EWR
15 goal. This change was enacted through Public Act 229 of 2023, which took effect on
16 February 13, 2024. The Company was already on a path to meeting this 1.5% EWR
17 mandate long before the Legislature and the Governor increased the mandate. Since 2017,
18 the Company's electric deliveries forecast factored in its commitment to help customers
19 reduce energy waste by at least 1.5% per year.

20 **Q. What level of EWR savings is included in the test year deliveries?**

21 A. From 2024 to the test year, the Company is expected to grow EWR savings to 1.9%, as
22 filed in the Company's latest IRP proceeding, Case No. U-21090. At the test year, the

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Company's projected EWR savings are 1.7%, with the residential class being projected at 1.1% and the business class (C&I) is projected at savings of around 1.8%.

Q. Please describe the process used to determine the Company's total generation requirements.

A. The forecasted total electric deliveries are increased by a line loss factor as determined by the 2023 System Loss Study to arrive at the Company's total generation requirements, i.e. system output, shown in Exhibit A-15 (EMB-2), Schedule E-1, and Exhibit A-15 (EMB-5), Schedule E-4.

Q. Is the 2023 System Loss Study the latest available?

A. The 2023 System Loss Study was the latest available at the time the test-year projections were created for this case.

Q. Please explain Exhibit A-52 (EMB-6).

A. Exhibit A-52 (EMB-6) calculates the projected test year PSCR Factor based on the electric deliveries and power supply expenses used in this case.

SECTION V. FORECASTED PEAK DEMAND

Q. What are the expectations for growth in peak demand?

A. The Company uses regression analysis based on the predicted level of electric deliveries to forecast the peak demand. Weather-normal peak demand grew at a 1.6% CAGR from 2003 to 2007 but reversed much of this trend during the 2007 to 2009 recession. Looking forward, peak demand is expected to increase 0.5% per year from 2024 to 2029. The monthly system level results of the electric peak demand forecast process is shown in Exhibit A-15 (EMB-5), Schedule E-4.

1 **Q. What is the impact to the peak demand forecast from the Company's Smart Energy**
2 **programs?**

3 A. The peak demand forecast is reduced by approximately 34 MW in 2025 to 40 MW in 2029
4 for the Company's DPP programs, which consist of Peak Time Rewards and Critical Peak
5 Pricing.

6 **Q. Are there any other adjustments to peak demand?**

7 A. Yes. In 2025, EWR and CVR measures are estimated to reduce peak demand by 869 MW
8 and 62 MW, respectively. This cumulative reduction to peak demand is projected to
9 increase to 1004 MW (EWR) and 87 MW (CVR) in the test year.

10 **Q. Are capacity-side demand response ("DR") resources accounted for in the**
11 **Company's peak demand forecast?**

12 A. No. Capacity-side DR resources, such as Residential AC Peak Cycling and C&I DR, which
13 includes Rate GI and Rate EIP, are registered with Midcontinent Independent System
14 Operator, Inc. and are accounted for outside of this peak demand forecast. Company
15 witness Megan L. Metz supports the capacity-side DR in her testimony.

16 **Q. To what extent is the Company's RSP rate expected to impact peak demand?**

17 A. Rate RSP is expected to reduce the Company's peak demand by approximately 66 MW in
18 the test year.

19 **Q. What process is used to identify the peak demand impacts of the Company's EWR**
20 **programs?**

21 A. The Company developed hourly load profiles for the EWR programs. The monthly energy
22 savings associated with each of these programs are integrated with the corresponding load
23 shape to develop hourly demand savings curves.

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1 **Q. Does this conclude your direct testimony?**

2 **A. Yes.**

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

ANN E. BULKLEY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am a Principal at The Brattle Group (“Brattle”), a consulting firm that advises clients on regulatory finance and ratemaking issues.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this direct testimony before the Michigan Public Service Commission (“MPSC” or the “Commission”) on behalf of Consumers Energy Company (“Consumers Energy” or the “Company”).

Q. Please describe your background and professional experience in the energy and utility industries.

A. I hold a Bachelor’s degree in Economics and Finance from Simmons College and a Master’s degree in Economics from Boston University, and have more than 30 years of experience consulting to the energy industry. I have provided testimony regarding financial matters, including the cost of capital, before numerous regulatory agencies. I have advised energy and utility clients on a wide range of financial and economic issues, with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. A summary of my professional and educational background is presented in Attachment A to this testimony.

1 **II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY**

2 **Q. What is the purpose of your direct testimony?**

3 A. The purpose of my direct testimony is to present evidence and provide a recommendation
4 regarding the return on equity (“ROE”) for Consumers Energy’s electric utility operations
5 to be used for ratemaking purposes.

6 **Q. Are you sponsoring any exhibits with your direct testimony?**

7 A. Yes. My analysis and recommendations are supported by data presented in Exhibit A-14
8 (AEB-1) Schedule D-5 - Cost of Common Shareholder’s Equity, which were prepared by
9 me or under my direction.

10 **Q. Please provide a brief overview of the analyses that support your ROE**
11 **recommendation.**

12 A. I estimate the market-based cost of equity by applying traditional estimation methodologies
13 to a proxy group of comparable utilities, including the constant growth form of the
14 Discounted Cash Flow (“DCF”) model, the Capital Asset Pricing Model (“CAPM”), the
15 Empirical Capital Asset Pricing Model (“ECAPM”), and a Bond Yield Risk Premium
16 (“BYRP” or “Risk Premium”) analysis. My recommendation also takes into consideration
17 the business and regulatory risk of the Company relative to the proxy group, and the
18 Company’s proposed capital structure as compared with the capital structures of the
19 operating utilities of the proxy group companies. While I do not make specific adjustments
20 to my ROE recommendation for these factors, I do consider them in the aggregate when
21 determining where my recommended ROE falls within the range of the analytical results.

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1 **Q. How is the remainder of your direct testimony organized?**

2 A. The remainder of my direct testimony is organized as follows:

- 3 • Section III provides a summary of my analyses and conclusions.
- 4 • Section IV reviews the regulatory guidelines pertinent to the development of
- 5 the cost of capital.
- 6 • Section V discusses current and projected capital market conditions and the
- 7 effect of those conditions on the Company's cost of equity.
- 8 • Section VI explains my selection of a proxy group of electric utilities used to
- 9 develop my analytical results.
- 10 • Section VII describes my cost of equity analyses and the basis for my
- 11 recommended ROE in this proceeding.
- 12 • Section VIII provides a discussion of specific regulatory, business, and
- 13 financial risks that have a direct bearing on the ROE to be authorized for the
- 14 Company in this case.
- 15 • Section IX presents my conclusions and recommendations for the market cost
- 16 of equity.

17 **III. SUMMARY OF ANALYSIS AND CONCLUSIONS**

18 **Q. Please summarize the key factors that you consider your analyses and upon which**
19 **you base your recommended ROE.**

20 A. My analyses and recommendations consider the following:

- 21 • The United States ("U.S.") Supreme Court's ("Court") *Hope* and *Bluefield*
- 22 decisions established the standards for determining a fair and reasonable authorized
- 23 ROE for public utilities, including consistency of the allowed return with the returns
- 24 of other businesses having similar risk, adequacy of the return to provide access to
- 25 capital and support credit quality, and the requirement that the result lead to just
- 26 and reasonable rates.¹
- 27 • The effect of current and prospective capital market conditions on the cost of equity
- 28 estimation models and on investors' return requirements.

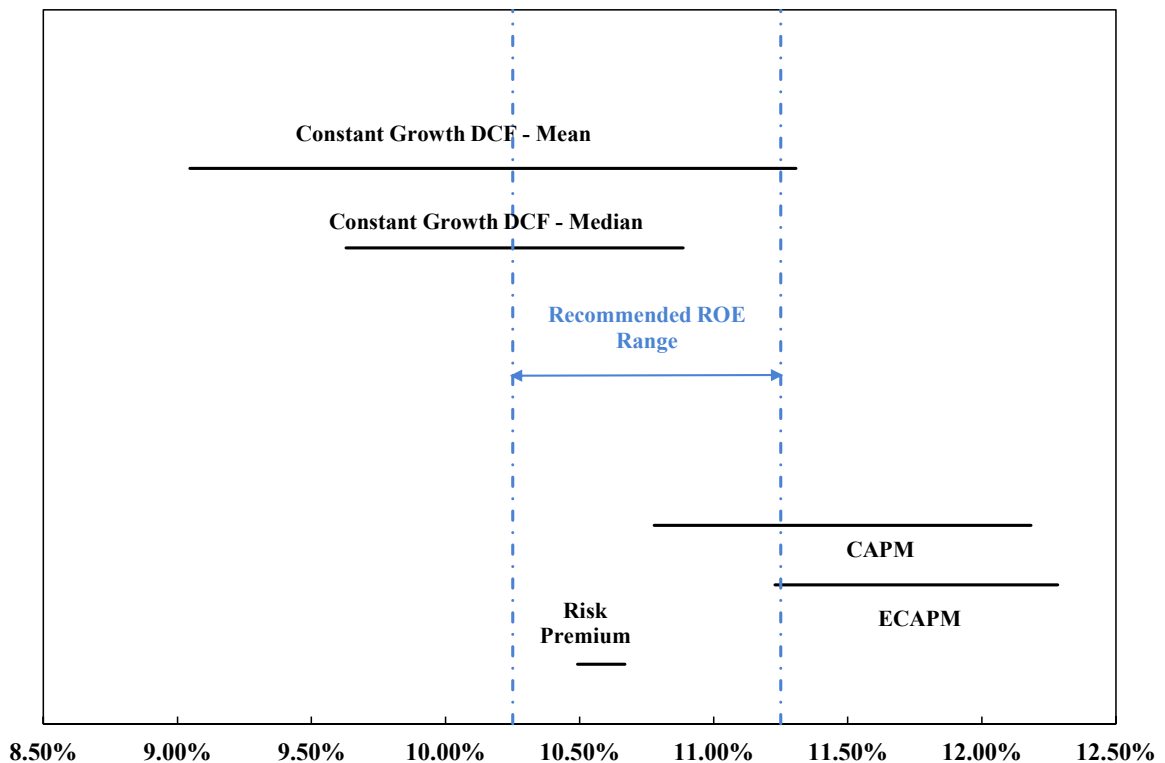
¹ Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) ("Hope"); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield").

- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (e.g., projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis).
- Although the companies in my proxy group are generally comparable to Consumers Energy, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I consider the Company's regulatory, business, and financial risks relative to a proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q. What are the results of the models that you have used to estimate the market-based cost of equity for Consumers Energy?

A. Figure 1 summarizes the range of results produced by the cost of equity analyses.

Figure 1: Summary of Cost of Equity Analytical Results



1 **Q. What is your recommended ROE for the Company in this proceeding?**

2 A. Considering the analytical results of the market-based cost of equity models, current and
3 prospective capital market conditions and the Company's regulatory, business, and
4 financial risk relative to the proxy group, I conclude that an ROE in the range of 10.25%
5 to 11.25% is reasonable, and within that range, the Company is requesting an ROE of
6 10.25% with a total capital structure that is composed of 42.94% equity and 41.55%
7 long-term debt.

8 **IV. REGULATORY GUIDELINES**

9 **Q. Please describe the principles that guide the establishment of the cost of capital for a**
10 **regulated utility.**

11 A. The Court's precedent-setting *Hope* and *Bluefield* cases established the standards for
12 determining the fairness or reasonableness of a utility's allowed ROE. Among the
13 standards established by the Court in those cases are: (1) consistency with other businesses
14 having similar or comparable risks; (2) adequacy of the return to support credit quality and
15 access to capital; and (3) the principle that the result reached, as opposed to the
16 methodology employed, is the controlling factor in arriving at just and reasonable rates.²

17 **Q. Has the Commission provided similar guidance in establishing the appropriate return**
18 **on common equity?**

19 A. Yes. For example, in its decision in Case No. U-20963, the Commission stated that:

20 The criteria for establishing a fair ROR for public utilities is
21 rooted in the language of the landmark United States (U.S.)
22 Supreme Court cases *Bluefield Waterworks & Improvement*
23 *Co v Public Serv Comm of West Virginia*, 262 US 679; 43 S

² *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

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Ct 675; 67 L Ed 1176 (1923), and *Federal Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court has made clear that, in establishing a fair ROR, consideration should be given to both investors and customers. As stated on page 12 of the December 23, 2008 order in U-15244 (December 23 order), “the rate of return should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise.” Nevertheless, the Commission observes that the determination of what is fair or reasonable, “is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use.” *Meridian Twp v City of East Lansing*, 342 Mich 734, 749; 71 NW2d 234 (1955).³

This guidance is in accordance with the *Hope* and *Bluefield* decisions and the principles that I have employed to estimate the cost of equity and ROE for the Company, including the principle that an allowed rate of return must be sufficient to enable regulated companies like Consumers Energy to attract capital on reasonable terms.

Q. Is fixing a fair rate of return just about protecting the utility’s interests?

A. No. As the Court noted in *Bluefield*, a proper rate of return not only assures “confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties.”⁴ As the Court went on to explain in *Hope*, “[t]he rate-making process ... involves balancing of the investor and consumer interests.”⁵

³ MPSC Case No. U-20963, December 22, 2021 Order, at 221-222.

⁴ *Bluefield*, 262 U.S. at 679, 693.

⁵ *Hope*, 320 U.S. at 591, 603.

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1 **Q. Why is it important for a utility to have a reasonable opportunity to earn a return**
2 **that is adequate to attract capital at reasonable terms?**

3 A. An ROE that is adequate to attract capital at reasonable terms enables the Company to
4 continue to provide safe, reliable electric service while maintaining its financial integrity.
5 The authorized return should be commensurate with returns expected elsewhere in the
6 market for investments of equivalent risk. If it is not, debt and equity investors will seek
7 alternative investment opportunities for which the expected return reflects the perceived
8 risks, thereby inhibiting the Company's ability to attract capital at reasonable cost, which
9 negatively affects customers.

10 **Q. Is a utility's ability to attract capital also affected by the ROEs that are authorized**
11 **for other utilities?**

12 A. Yes. Utilities compete directly for capital with other investments of similar risk, which
13 include other electric, natural gas, and water utilities nationally. Therefore, the ROE
14 authorized for a utility sends an important signal to investors regarding whether there is
15 regulatory support for financial integrity, dividends, growth, and fair compensation for
16 business and financial risk within that jurisdiction generally, and for that utility
17 particularly. The cost of capital represents an opportunity cost to investors. If higher
18 returns are available elsewhere for other investments of comparable risk over the same
19 time-period, investors have an incentive to direct their capital to those alternative
20 investments. Thus, an authorized ROE significantly below authorized ROEs for other
21 utilities can inhibit the utility's ability to attract capital for investment.

1 **Q. What is the standard for setting the ROE in any jurisdiction?**

2 A. The stand-alone ratemaking principle is a foundation of jurisdictional ratemaking. This
3 principle requires that the rates that are charged in any operating jurisdiction be for the
4 costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that
5 customers in each jurisdiction only pay for the costs of the service provided in that
6 jurisdiction, which is not influenced by the business operations in other operating
7 companies. Consistent with this principle, the cost of equity analysis is performed for an
8 individual operating company as a stand-alone entity. As such, I have evaluated the
9 investor-required return for Consumers Energy's electric utility operations in Michigan.

10 **Q. Does the fact that Consumers Energy is a wholly-owned subsidiary of CMS Energy**
11 **Corporation ("CMS"), a publicly-traded company, affect your analysis?**

12 A. No. In this proceeding, consistent with stand-alone ratemaking principles, it is appropriate
13 to establish the cost of equity for Consumers Energy's electric operations, not its
14 publicly-traded parent, CMS. More importantly, however, it is appropriate to establish a
15 cost of equity that provides the ability to attract capital on reasonable terms for Consumers
16 Energy's electric operations, both on a stand-alone basis and within CMS. While
17 Consumers Energy is committed to investing the required capital to provide safe and
18 reliable electric service, because it is a subsidiary of CMS, the Company competes with
19 the other CMS subsidiaries for discretionary investment capital. In determining how to
20 allocate its finite discretionary capital resources, it would be reasonable for CMS to
21 consider the authorized ROE of each of its subsidiaries.

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1 **Q. Are the regulatory framework, the authorized ROE, and equity ratio important to**
2 **the financial community?**

3 A. Yes. The regulatory framework is one of the most important factors in investors'
4 assessments of risk. Specifically, the authorized ROE and equity ratio for regulated utilities
5 is very important for determining the degree of regulatory support for reinforcing a utility's
6 creditworthiness and financial stability in the jurisdiction. To the extent authorized returns
7 in a jurisdiction are lower than the returns that have been authorized more broadly, such
8 actions are considered by both debt and equity investors in the overall risk assessment of
9 the regulatory jurisdiction in which the company operates. The direct testimony of
10 Company witness Marc R. Bleckman describes in further detail the effect of the authorized
11 ROE and equity ratio on credit quality as well as rating agencies' assessment of Michigan's
12 regulatory environment.

13 **Q. What are your conclusions regarding regulatory guidelines?**

14 A. The ratemaking process is premised on the principle that, in order for investors and
15 companies to commit the capital needed to provide safe and reliable utility services, a
16 utility must have a reasonable opportunity to recover the return of, and the market-required
17 return on, its invested capital. Accordingly, the Commission's order in this proceeding
18 should establish rates that provide the Company with a reasonable opportunity to earn a
19 ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its
20 financial integrity; and (3) commensurate with returns on investments in enterprises with
21 similar risk. It is important for the ROE authorized in this proceeding to take into
22 consideration current and projected capital market conditions, as well as investors'

1 expectations and requirements for both risks and returns. Because utility operations are
2 capital-intensive, regulatory decisions should enable the utility to attract capital at
3 reasonable terms under a variety of economic and financial market conditions. Providing
4 the opportunity to earn a market-based cost of capital supports the financial integrity of the
5 Company, which is in the interest of both customers and shareholders.

6 **V. CAPITAL MARKET CONDITIONS**

7 **Q. Why is it important to analyze capital market conditions?**

8 A. Capital market conditions influence cost of equity models by affecting inputs in the model
9 at the time the analysis is performed. While the ROE that is established in a rate proceeding
10 is intended to be forward-looking, the analyst uses current and projected market data,
11 specifically stock prices, dividends, growth rates and interest rates, in the models to
12 estimate the required return for the subject company.

13 Analysts and regulatory commissions recognize the importance of considering how
14 these conditions impact cost of equity estimation models when determining the appropriate
15 range and recommended ROE for a future period. If investors do not expect current market
16 conditions to be sustained in the future, it is possible that the cost of equity estimation
17 models will not provide an accurate estimate of investors' required return during that rate
18 period. Therefore, it is important to consider projected market data to estimate the return
19 of the forward-looking period.

20 **Q. What has the level of inflation been over the past few years?**

21 A. As shown in Figure 2, year-over-year core inflation increased steadily beginning in early
22 2021, rising from 1.40% in January 2021 to a high of 6.64% in September 2022, which

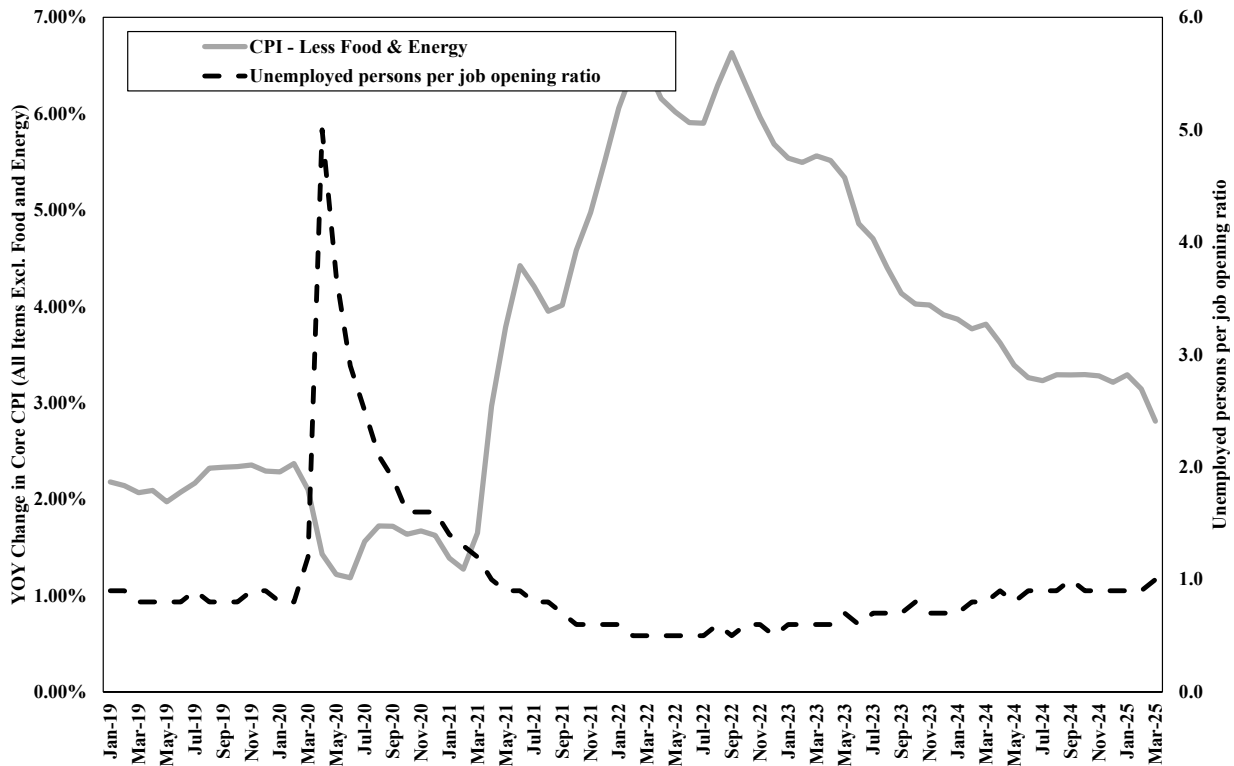
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1 was the largest 12-month increase since 1982.⁶ While core inflation has declined in
2 response to the Federal Reserve’s monetary policy, it continues to remain significantly
3 above the Federal Reserve’s target level of 2.00%.

4 Because the Federal Reserve’s dual mandate is to promote stable prices and
5 employment, considering employment data, in addition to inflation, is important. The ratio
6 of unemployed persons per job opening was 1.00 in March 2025 (the most recent data
7 available at the time of this testimony) and has been consistently below 1.00 since
8 April 2021, suggesting a tighter labor market. This indicates sustained strength in the labor
9 market, allowing the Federal Reserve to prioritize reducing inflation by pursuing the
10 necessary restrictive monetary policy needed to achieve its 2.00% target benchmark.

⁶ Reade Pickert, Core US inflation rises to 40-year high, securing big Fed hike, *Bloomberg*, October 13, 2022.

**Figure 2: Core Inflation and Unemployed Persons-to-Job Openings,
January 2019 to March 2025⁷**



Q. What policy actions did the Federal Reserve enact to respond to increased inflation?

A. The dramatic increase in inflation prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Between the March 2022 Federal Open Market Committee (“FOMC”) meeting and the July 2023 FOMC meeting, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00% to 0.25% to a range of 5.25% to 5.50%.

⁷ Bureau of Labor Statistics; most available data as of April 30, 2025.

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1 **Q. How did yields on long-term government bonds respond to the Federal Reserve's**
2 **normalization of monetary policy?**

3 A. Since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds
4 increased by over 350 basis points, increasing from 1.47% on December 15, 2021 to a peak
5 of 4.98% in October 2023. It currently remains well above 2021 levels (i.e., 4.17% as of
6 April 30, 2025).⁸

7 **Q. Did the Federal Reserve recently reduce the federal funds rates?**

8 A. Yes. The Federal Reserve did recently reduce the federal funds rate by 50 basis points in
9 September 2024, 25 basis points in November 2024, and 25 basis points in December 2024
10 noting at the September meeting the reduction was due to the risks associated with both
11 inflation and the labor market becoming more balanced given the effectiveness of
12 restrictive monetary policy in combatting inflation. However, the Federal Reserve left
13 rates unchanged at the most recent FOMC meetings in January and March 2025.

14 **Q. What is the expected path of monetary policy over the near-term?**

15 A. At the March 2025 FOMC meeting, Chairman Powell noted that labor market conditions
16 are "solid" and while inflation has declined it still remains above the Federal Reserve's
17 target of 2%, as a result, the FOMC decided to maintain the current federal fund rate range
18 of 4.25% to 4.50%.⁹ Regarding the possible path of monetary policy, Chairman Powell
19 continued to reiterate that policy is "not on any preset course"; but, he acknowledged
20 increased uncertainty due to the implementation of significant policy changes (i.e., trade,

⁸ S&P Capital IQ Pro.

⁹ Transcript of Chair Powell's Press Conference, March 19, 2025.

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1 immigration, fiscal policy and regulation) by the Trump administration.¹⁰ Chairman Powell
2 noted that the FOMC will continue to analyze incoming data to determine the effect of
3 such policy changes and was in a good position to adjust the course of monetary policy if
4 needed.¹¹ Thus, the FOMC's forecast of the federal funds rate remained unchanged from
5 the December 2024 meeting, forecasting just two rate cuts before the end of 2025.¹²

6 **Q. What has happened to the yields on long-term government bonds since the FOMC**
7 **reduced the federal funds rate in September 2024?**

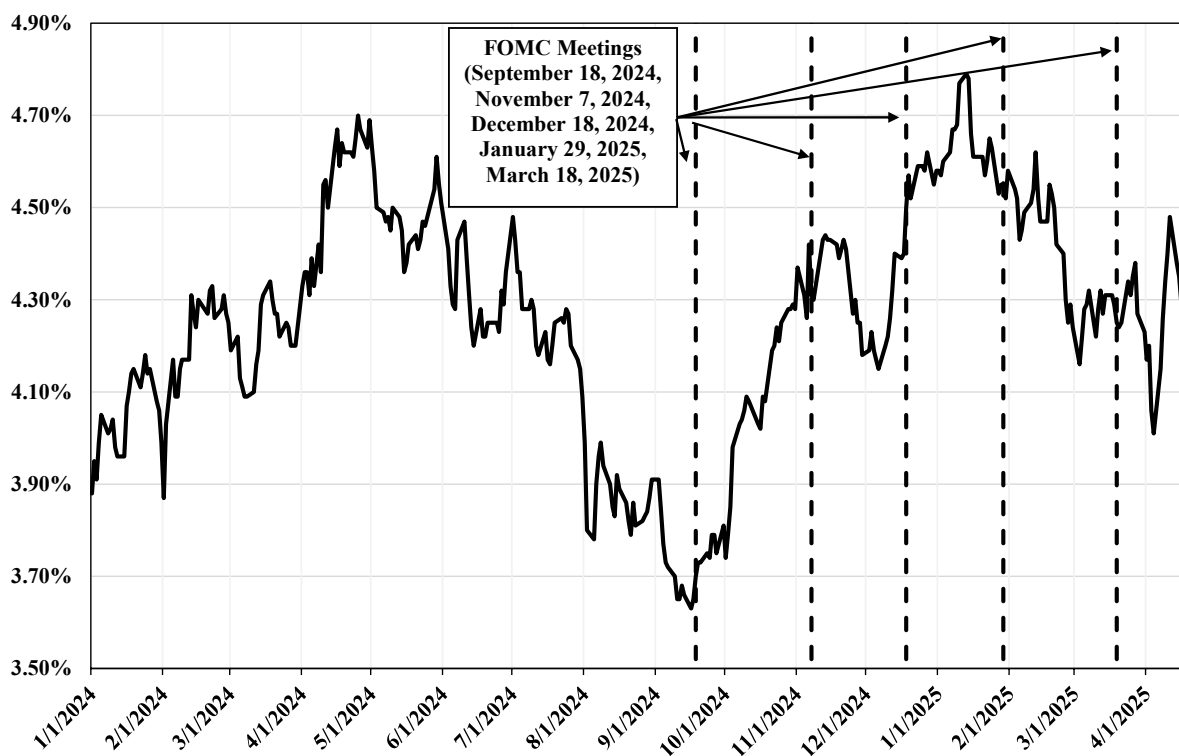
8 A. As shown in Figure 3 below, while the yield on the 10-year treasury bond declined prior to
9 the time of the first federal funds rate cut, the yield has increased since the September 2024
10 FOMC meeting. As of April 21, 2025, the 10-year Treasury bond yield was 4.42%, which
11 is consistent with levels seen in June 2024, several months prior to the reductions in the
12 federal funds rate.

¹⁰ *Id.*

¹¹ *Id.*

¹² Federal Reserve, Summary of Economic Projections, March 19, 2025, at 2.

Figure 3: 10-Year Treasury Bond Yield, January 2024 through April 21, 2025¹³



1 **Q. Why have long-term interest rates increased since the Federal Reserve reduced the**
2 **federal funds rate in September 2024?**

3 A. Investors view key elements of President Trump’s economic plan, such as tax cuts,
4 immigration policy, and tariffs, as inflationary. According to a recent *Reuters* article, the
5 increase in long-term government bond yields was initially related to investors responding
6 to an increasing probability of a Trump Administration in 2025 and has continued since
7 President Trump’s re-election and inauguration.¹⁴ For example, on April 2, 2025, President
8 Trump announced a significant set of tariffs on each of the U.S.’s trading partners, a policy

¹³ S&P Capital IQ Pro.

¹⁴ Davide Barbuscia and Lewis Krauskopf, “Bond rebound uncertain as Trump plans overshadow Fed rate cuts,” *Reuters*, November 8, 2024.

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1 initiative that is largely viewed as inflationary. Inflation affects bonds, in particular
2 long-term government bonds, because it erodes the value of future bonds payments.
3 Therefore, in an inflationary environment, investors will demand higher returns on bonds
4 to compensate for the added risk of inflation thus bond prices decline and the yields on
5 bonds increase. The longer the duration of the bond, the greater the effect of inflation
6 which is why inflation risk is greater for long-term government bonds. The significant
7 tariff policy increases the risk that inflation will remain elevated, which is why the yields
8 on long-term bonds have not decreased and in fact have increased since the Federal Reserve
9 reduced the federal funds rate. Further, the use of tariffs strains the relationship with
10 trading partners, which could result in a reduction in the foreign demand for long-term U.S.
11 government bonds resulting in additional upward pressure on long-term government bond
12 yields.¹⁵

13 **Q. What are expectations for the yields on long-term government bonds?**

14 A. Economists and analysts are expecting elevated rates. *Blue Chip Financial Forecasts*
15 provides a forecast from economists on the 30-year Treasury bond. In the most recent
16 published *Blue Chip Financial Forecasts* report, economists projected the 30-year treasury
17 rate to remain relatively stable and decrease only slightly from 4.60% in Q2/2025 to 4.40%
18 in Q2/2026.¹⁶ Additionally, the consensus estimate over the longer-term (i.e., 2026-2030)
19 as published in the December 2024 *Blue Chip Financial Forecasts* report was 4.30%.¹⁷

¹⁵ Vanjani, Karishma. "U.S. Treasury Bonds Sell Off as 30-Year Yield Rises Most Since 1982," *Barron's*, April 9, 2025.

¹⁶ *Blue Chip Financial Forecasts*, Vol. 44, No. 5, May 1, 2025, at 2.

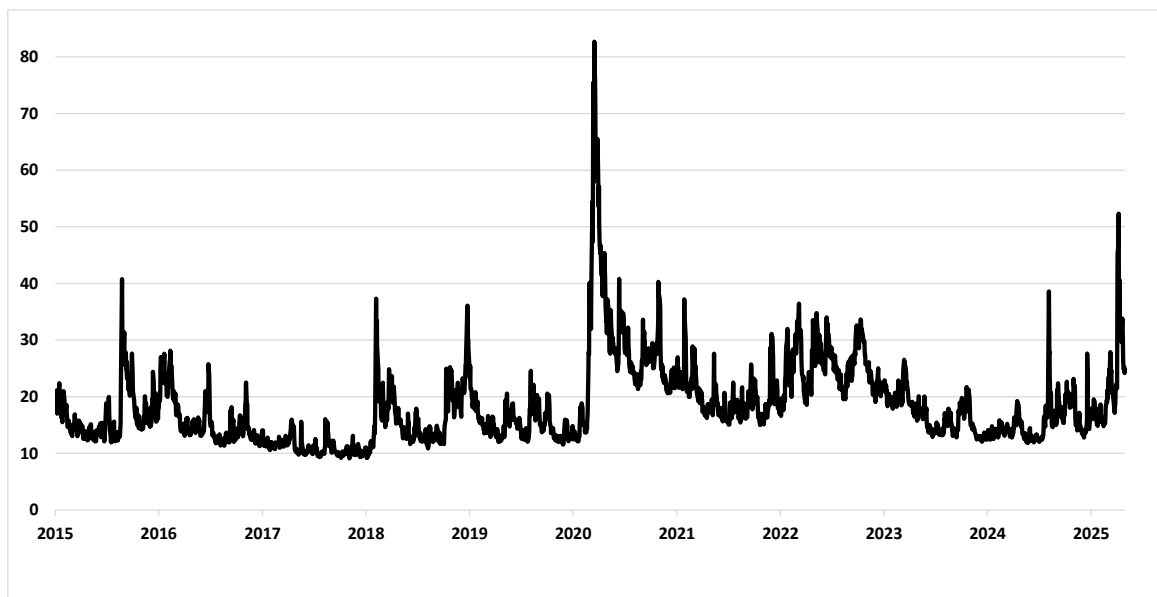
¹⁷ *Blue Chip Financial Forecasts*, Vol. 43, No. 12, November 27, 2024, at 14.

1 This is important because it means that long-term interest rates are expected to remain
2 elevated during the period that the Company's rates will be in effect.

3 **Q. Has the recent tariff policy of the Trump Administration resulted in increased**
4 **volatility in financial markets?**

5 A. Yes, financial markets have been extremely volatile since President Trump announced a
6 significant set of tariffs on April 2, 2025. For example, as shown in Figure 4, the CBOE
7 Volatility Index ("VIX"), which measures investors' expectation of volatility in the
8 Standard and Poor's ("S&P") 500 over the next 30 days, has been above 30 since April 2,
9 2025, and peaked at 52.33 on April 8, 2025. The VIX has not reached 50.00 since April
10 2020 during the height of the COVID-19 pandemic. The high level of uncertainty
11 associated with the economic effects of the Trump Administration's tariff policy has
12 resulted in significant volatility increasing the risk of holding equity investments and
13 implying an increase in the cost of equity.

Figure 4: CBOE VIX – January 2015 – April 2025



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1 **Q. Have you reviewed any other indicators that show uncertainty has increased as a**
2 **result of the Trump Administration's tariff policy?**

3 A. Yes. In addition to the recent high volatility as measured by the VIX, the University of
4 Michigan's consumer sentiment index indicates consumer sentiment is at its second lowest
5 point since 1952 and that inflation expectations are at the highest levels in 44 years.¹⁸
6 Furthermore, a recent Bank of America Global Fund Manager Survey conducted in
7 April 2025, shows investor sentiment at its 5th lowest point since the study began in 2001.¹⁹

8 **Q. What are your conclusions regarding the effect of current market conditions on the**
9 **cost of equity for the Company?**

10 A. It is important to consider current and projected market conditions in setting the forward-
11 looking ROE due to its effect on the estimated cost of equity. Long-term interest rates
12 remain elevated and are expected to continue to remain elevated as a result of inflationary
13 policies such as tariffs, immigration policy, and tax cuts. While the FOMC reduced the
14 federal funds rate three times at the end of 2024, rates were unchanged at the first meetings
15 of 2025 and Chairman Powell has indicated that the Federal Reserve is in wait and see
16 mode and will rely on incoming data to determine when it is appropriate to adjust the
17 federal funds rate. With higher expected interest rates, borrowing is more expensive which
18 in turn raises the cost of capital. As a result, investors demand higher returns on equity,
19 leading to an increase in the cost of equity.

¹⁸ Harriet Torry. "From anxious to petrified": Consumer sentiment plunges further," *Wall Street Journal*. April 11, 2025.

¹⁹ Michael Hartnett et al., "Global Fund Manager Survey: The Bear Necessities," *BoA Global Research*. April 15, 2025.

1 **VI. PROXY GROUP SELECTION**

2 **Q. Please provide a brief profile of Consumers Energy's electric utility operations.**

3 A. Consumers Energy is a wholly-owned subsidiary of CMS. The Company provides electric
4 service to approximately 1.9 million customers in Michigan with approximately
5 \$5.1 billion in operating revenues from electric services.²⁰ As of December 31, 2024, the
6 Company's net utility electric plant was approximately \$11.3 billion.²¹ Consumers Energy
7 currently has an investment-grade long-term rating of A- from S&P and A3 from Moody
8 Investors Service's ("Moody's").²²

9 **Q. Why have you used a group of proxy companies to estimate the cost of equity for**
10 **Consumers Energy?**

11 A. In this proceeding, the cost of equity is being estimated for an electric utility that is not
12 itself publicly traded. Because the cost of equity is a market-based concept and the
13 Company's operations do not make up the entirety of a publicly traded entity, it is necessary
14 to establish a group of companies that is both publicly traded and comparable to the
15 Company in certain fundamental business and financial respects to serve as its "proxy" for
16 purposes of estimating the cost of equity.

17 Even if the Company was a publicly traded entity, it is possible that transitory
18 events could bias its market value over a given period. A significant benefit of using a
19 proxy group is that it moderates the effects of unusual events that may be associated with
20 any one company. The proxy companies used in my analyses all possess a set of operating

²⁰ Consumers Energy Corporation, 2024 SEC Form 10-K, December 31, 2024, at 18.

²¹ Exhibit A-2 (PDD-4), Schedule B-2.

²² S&P Global Market Intelligence, accessed April 4, 2025. Moody's as of April 4, 2025.

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1 and risk characteristics that are substantially comparable to the Company, and thus provide
2 a reasonable basis to estimate the appropriate cost of equity for the Company.

3 **Q. How did you select the companies included in your proxy group?²³**

4 A. I began with the group of 36 companies that Value Line classifies as Electric Utilities and
5 applied the following screening criteria to select companies that:

- 6 • pay consistent quarterly cash dividends, because companies that do not cannot
7 be analyzed using the Constant Growth DCF model;
- 8 • have investment grade long-term issuer ratings;
- 9 • have positive long-term earnings growth forecasts from at least two utility
10 industry equity analysts;
- 11 • own regulated generation assets that are included in rate base;
- 12 • derive more than 40.00% of their megawatt-hour sales from their owned
13 generation facilities;
- 14 • derive more than 60.00% of their total operating income from regulated electric
15 operations; and
- 16 • were not parties to a merger or transformative transaction during the analytical
17 periods relied on.

18 **Q. Did you include CMS in your proxy group?**

19 A. No. Consistent with my general practice of excluding the subject company, or its parent
20 holding company, from the proxy group, I exclude CMS from my proxy group for
21 Consumers Energy.

²³ In prior testimonies, I relied on two separate screens based on operating income that required proxy group companies to have derived more than 60.00% of operating income from regulated operations and derived more than 80.00% of total regulated operating income from regulated electric operations. Intervenors in prior cases contended that the use of the two separate operating income screens was overly restrictive and resulted in the exclusion of companies that investors would consider comparable to Consumers Energy. As a result, I am currently relying on one operating income screen that requires a company derive more than 60.00% of total operating income from regulated electric operations. This revised screen still ensures that the companies in my proxy group derive a majority of their operating income from regulated electric operations similar to Consumers Energy.

1 **Q. What is the composition of your proxy group?**

2 A. The screening criteria discussed above is shown in Exhibit A-14 (AEB-1), Schedule D-5,
3 page 2 and results in a proxy group consisting of the companies shown in Figure 5.

Figure 5: Proxy Group

Company	Ticker
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
Dominion Resources, Inc.	D
DTE Energy Company	DTE
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
TXNM Energy	TXNM
Portland General Electric Company	POR
PPL Corporation	PPL
Southern Company	SO
Xcel Energy Inc.	XEL

4 **VII. COST OF EQUITY ESTIMATION**

5 **Q. Please briefly discuss the ROE in the context of a regulated utility.**

6 A. The rate of return for a regulated utility is the weighted average cost of capital, in which
7 the costs of the individual sources of capital are weighted by their respective proportion

1 (i.e., book values) in the utility's capital structure. The ROE is the cost rate applied to the
2 equity capital in calculating the rate of return. While the costs of debt and preferred stock
3 can be directly observed, the cost of equity is market-based and, therefore, must be
4 estimated based on observable market data when establishing the ROE.

5 **Q. How is the required cost of equity determined?**

6 A. The required cost of equity is estimated by using analytical techniques that rely on
7 market-based data to quantify investor expectations regarding equity returns, adjusted for
8 certain incremental costs and risks. Informed judgment is then applied to determine where
9 the company's cost of equity falls within the range of results produced by multiple
10 analytical techniques. The key consideration in determining the cost of equity is to ensure
11 that the methodologies employed reasonably reflect investors' views of the financial
12 markets in general, as well as the subject company (in the context of the proxy group), in
13 particular.

14 **Q. What methods did you use to estimate the cost of equity for the Company in this**
15 **proceeding?**

16 A. I consider the results of the constant growth form of the DCF model, the CAPM, the
17 ECAPM, and a BYRP analysis. A reasonable cost of equity estimate appropriately
18 considers alternative methodologies and the reasonableness of their individual and
19 collective results.

20 **Q. Why is it important to use more than one analytical approach?**

21 A. Because the cost of equity is not directly observable, it must be estimated based on both
22 quantitative and qualitative information. When faced with the task of estimating the cost

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of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin²⁴ suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski²⁵ recommend the CAPM, DCF, and BYRP approaches.

Q. Has the Commission also recognized the benefits of using more than one model to estimate the cost of equity?

A. Yes. In its order in Case No. U-21291 for DTE Gas Company, the Commission noted that the evidence that is presented by the parties in each case should be considered in determining the authorized return for the subject company. Specifically, the Commission stated:

With respect to the ROE methodologies, the Commission finds that it is not limited to considering methodologies as approved by FERC. Specifically, the Commission agrees with the Staff that:

[t]he Commission has a history of staying agnostic on what models are presented, and hearing arguments both for and against any model on a case-by-case basis. This not only aligns well with Bluefield and Hope, which do not endorse a particular model or set of models but is paramount as many witnesses include different inputs and adjustments to their models. This flexibility in utilizing different inputs and adjustments cannot

²⁴ Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies* (3rd ed. 2000), at 214.

²⁵ Eugene Brigham and Louis Gapenski, *Financial Management: Theory and Practice* (7th ed. 1994), at 341.

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be accounted for in a system where the Commission directly prescribes the use of specific models to analysts.

Staff's exceptions, pp. 8-9. The Commission agrees that the evidence presented in each case should be considered in arriving at an approved ROE for the utility. As noted in the PFD, the appropriateness of the use of the risk premium model is in flux before FERC and, at this time, the Commission declines to make a bright line rule about the applicability or appropriateness of this, or any one model as a whole. Similarly, the Commission declines to require an additional analysis regarding the risk premium model in the company's next rate case as recommended by the ALJ. See, PFD, p. 209. The Commission will continue to review the evidence presented by the parties giving appropriate weight and consideration to each methodology presented on each record in each case.²⁶

A. Constant Growth DCF Model

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \dots + \frac{D_\infty}{(1+k)^\infty} \quad [1]$$

Where P_0 represents the current stock price, $D_1 \dots D_\infty$ are all expected future dividends, and k is the discount rate, or required COE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \quad [2]$$

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

²⁶ MPSC Case No. U-21291, November 7, 2024 Order, at 106-107.

1 **Q. What assumptions are required for the Constant Growth DCF model?**

2 A. The Constant Growth DCF model requires the following assumptions: (1) a constant
3 growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant
4 price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To
5 the extent that any of these assumptions are violated, considered judgment and/or specific
6 adjustments should be applied to the results.

7 **Q. What market data did you use to calculate the dividend yield in your Constant**
8 **Growth DCF model?**

9 A. The dividend yield in my Constant Growth DCF model is based on the proxy companies'
10 current annual dividend and average closing stock prices over the 30-, 90-, and 180-trading
11 days as of March 31, 2025.

12 **Q. Why did you use three averaging periods for stock prices?**

13 A. In my Constant Growth DCF model, I use an average of recent trading days to calculate
14 the term P_0 in the DCF model to ensure that the cost of equity is not skewed by anomalous
15 events that may affect stock prices on any given trading day. The averaging period should
16 also be reasonably representative of expected capital market conditions over the long term.

17 **Q. Did you make any adjustments to the dividend yield to account for periodic growth**
18 **in dividends?**

19 A. Yes. Because utility companies tend to increase their quarterly dividends at different times
20 throughout the year, it is reasonable to assume that dividend increases will be evenly
21 distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half
22 of the expected annual dividend growth rate for purposes of calculating the expected

1 dividend yield component of the DCF model. This adjustment ensures that the expected
2 first-year dividend yield is, on average, representative of the coming twelve-month period,
3 and does not overstate the aggregated dividends to be paid during that time.

4 **Q. Why is it important to select appropriate measures of long-term growth in applying**
5 **the DCF model?**

6 A. In its constant growth form, the DCF model (*i.e.*, Equation [2] shown previously) assumes
7 a single long-term growth rate in perpetuity. In order to reduce the long-term growth rate
8 to a single measure, one must assume that the dividend payout ratio remains constant and
9 that earnings per share (“EPS”), dividends per share, and book value per share all grow at
10 the same constant rate. However, over the long run, dividend growth can only be sustained
11 by earnings growth, meaning earnings are the fundamental driver of a company’s ability
12 to pay dividends. Therefore, projected EPS growth is the appropriate measure of a
13 company’s long-term growth. In contrast, changes in a company’s dividend payments are
14 based on management decisions related to cash management and other factors. For
15 example, a company may decide to retain earnings rather than pay out a portion of those
16 earnings to shareholders through dividends. Therefore, dividend growth rates are less
17 likely than earnings growth rates to accurately reflect investor perceptions of a company’s
18 growth prospects. Accordingly, I have incorporated a number of sources of long-term EPS
19 growth rates into the Constant Growth DCF model.

1 **Q. What sources of long-term growth rates did you rely on in your Constant Growth**
2 **DCF model?**

3 A. My Constant Growth DCF model incorporates three sources of long-term projected EPS
4 growth rates: (1) *Zacks Investment Research (Zacks)*; (2) *S&P Capital IQ*; and (3) *Value*
5 *Line*.

6 **Q. Have you previously relied on projected EPS growth rates provided by *Yahoo!***
7 ***Finance*?**

8 A. Yes, however, *Yahoo! Finance* no longer reports consensus projected 3- to 5-year EPS
9 growth rates. As a result, I now instead rely on the consensus projected 3- to 5-year EPS
10 growth rates reported by *S&P Capital IQ*.

11 **Q. How do you calculate the range of results for the Constant Growth DCF models?**

12 A. I calculate the low-end result for the Constant Growth DCF model using the minimum
13 growth rate of the three sources (*i.e.*, the lowest of the *Zacks*, *S&P Capital IQ*, and *Value*
14 *Line* projected EPS growth rates) for each of the proxy group companies. I use a similar
15 approach to calculate a high-end result, using the maximum growth rate of the three sources
16 for each proxy group company. Lastly, I also calculate results using the average EPS
17 growth rate from all three sources for each proxy group company.

18 **Q. Please summarize the results of your Constant Growth DCF analyses.**

19 A. The results of my Constant Growth DCF analyses are presented in Exhibit A-14 (AEB-1),
20 Schedule D-5, pages 3-5 and are summarized in Figure 6 below.

Figure 6: Summary of Constant Growth DCF Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	8.92%	10.24%	11.18%
90-Day Avg. Stock Price	9.06%	10.38%	11.32%
180-Day Avg. Stock Price	9.16%	10.47%	11.42%
Average	9.05%	10.36%	11.31%
Median Results:			
30-Day Avg. Stock Price	9.47%	10.07%	10.77%
90-Day Avg. Stock Price	9.62%	10.27%	10.88%
180-Day Avg. Stock Price	9.79%	10.43%	11.01%
Average	9.63%	10.26%	10.89%

B. Capital Asset Pricing Model

Q. Please briefly describe the Capital Asset Pricing Model.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or “systematic” risk of that security.²⁷ This second component is the product of the market risk premium and the beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) [3]$$

Where:

K_e = the required market COE;

²⁷ Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

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β = the beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

In this specification, the term $(r_m - r_f)$ represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Systematic risk is measured by beta, which is a measure of the volatility of a security as compared to the market as a whole. Beta is defined as:

$$\beta = \frac{\text{Covariance}(r_e, r_m)}{\text{Variance}(r_m)} \quad [4]$$

Variance (r_m) represents the variance of the market return, which is a measure of the uncertainty of the general market. *Covariance* (r_e, r_m) represents the covariance between the return on a specific security and the general market, which reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

Q. What risk-free rate did you use in your CAPM analyses?

A. I use three estimates of the yield on Treasury bonds: (1) the current 30-day average yield on 30-year Treasury bonds (4.61%);²⁸ (2) the projected 30-year Treasury yield for Q2 2025 through Q2 2026 (4.52%);²⁹ and (3) the projected 30-year Treasury yield for the period 2026-2030 (4.30%).³⁰

²⁸ Bloomberg Professional as of March 31, 2025.

²⁹ *Blue Chip Financial Forecasts*, Vol. 44, No. 4, April 1, 2025, at 2.

³⁰ *Blue Chip Financial Forecasts*, Vol. 43, No. 12, November 27, 2024, at 14.

1 **Q. What beta coefficients did you use in your CAPM analysis?**

2 A. As shown in Exhibit A-14 (AEB-1), Schedule D-5, pages 6-11, I use the beta coefficients
3 for the proxy group companies as reported by *Bloomberg* and *Value Line*. The beta
4 coefficients reported by *Bloomberg* are calculated using ten years of weekly returns relative
5 to the S&P 500 Index. The beta coefficients reported by *Value Line* are calculated based
6 on five years of weekly returns relative to the New York Stock Exchange Composite Index.
7 Additionally, as shown in Exhibit A-14 (AEB-1), Schedule D-5, pages 12-14, I also
8 considered an additional CAPM analysis that relies on the long-term average utility beta
9 coefficient for the companies in my proxy group from 2013 through 2024, which are
10 presented in Exhibit A-14 (AEB-1), Schedule D-5, page 15.

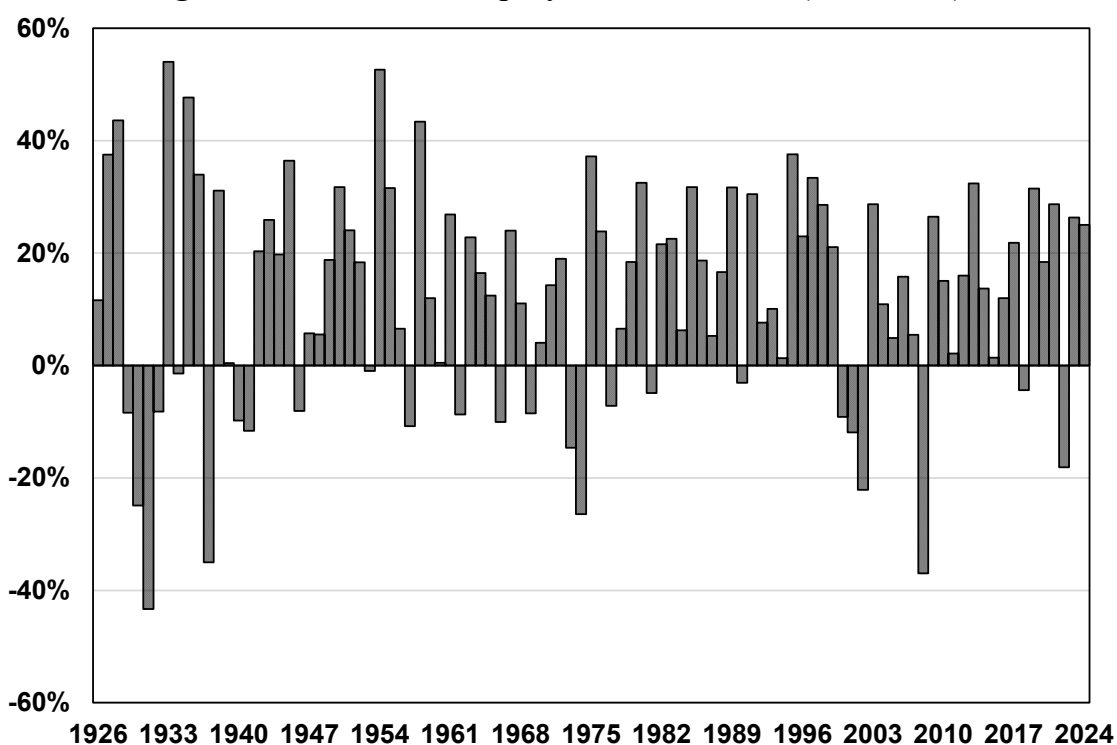
11 **Q. How do you estimate the market risk premium in the CAPM?**

12 A. I estimate the market risk premium as the difference between the implied expected equity
13 market return and the risk-free rate. As shown in Exhibit A-14 (AEB-1), Schedule D-5,
14 pages 16-21, the expected market return is calculated using the Constant Growth DCF
15 model discussed previously as applied to the companies in the S&P 500 Index. Based on
16 an estimated market capitalization-weighted dividend yield of 1.36% and a weighted
17 long-term growth rate of 11.15%, the estimated required market return for the S&P 500
18 Index as of March 31, 2025 is 12.58%. Based on the three risk-free rates considered, the
19 market risk premium ranges from 7.97% to 8.28%.

1 **Q. How does the expected market return compare to observed historical market**
2 **returns?**

3 A. As shown in Figure 7, given the range of annual equity returns that have been observed
4 over the past century, a current expected market return of 12.58% is not unreasonable. As
5 shown, in 52 out of the past 99 years (or roughly 53.00% of observations), the realized
6 equity market return was 12.58% or greater.

Figure 7: Realized U.S. Equity Market Returns (1926–2024)³¹



7 **Q. Did you consider another form of the CAPM in your analysis?**

8 A. Yes. I have also considered the results of an ECAPM in estimating the cost of equity for
9 the Company.³² The ECAPM calculates the product of the adjusted beta coefficient and

³¹ Depicts total annual returns on large company stocks, as reported in the 2023 *Kroll S&P* Yearbook for 1926-2022 and from *S&P Capital IQ Professional* for 2023 and 2024.

³² See, e.g., Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., June 1, 2006, at 189.

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1 the market risk premium and applies a weight of 75.00% to that result. The model then
2 applies a 25.00% weight to the market risk premium without any effect from the beta
3 coefficient. The results of the two calculations are summed, along with the risk-free rate,
4 to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [5]$$

Where:

k_e = the required market COE;

β = adjusted beta coefficient of an individual security;

r_f = the risk-free rate of return; and,

r_m = the required return on the market as a whole.

5 The ECAPM addresses the tendency of the “traditional” CAPM to underestimate the cost
6 of equity for companies with low beta coefficients such as regulated utilities. In that regard,
7 the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM, but
8 rather it recognizes the results of academic research indicating that the risk-return
9 relationship is different (in essence, flatter) than estimated by the CAPM, meaning that the
10 CAPM underestimates the cost of equity for companies with a beta less than 1.0 and
11 overestimates the cost of equity for companies with a beta greater than 1.0.³³

12 Consistent with my CAPM, my application of the ECAPM uses the forward-
13 looking market risk premium estimates, the three yields on 30-year Treasury securities
14 noted earlier as the risk-free rate, and the current *Bloomberg*, current *Value Line*, and
15 long-term *Value Line* beta coefficients.

³³ *Id.*, at 191.

Q. What are the results of your CAPM and ECAPM analyses?

A. The results of my CAPM and ECAPM analyses are presented in Exhibit A-14 (AEB-1), Schedule D-5, pages 6-14 and are summarized in Figure 8 below.

Figure 8: CAPM and ECAPM Results

	30-Year Treasury Bond Yield		
	Current	Near-Term	Longer-Term
	30-Day Avg	Projected	Projected
CAPM:			
Current <i>Value Line</i> Beta	12.18%	12.18%	12.17%
Current Bloomberg Beta	10.85%	10.83%	10.78%
Long-term Avg. <i>Value Line</i> Beta	10.85%	10.83%	10.79%
ECAPM:			
Current <i>Value Line</i> Beta	12.28%	12.28%	12.27%
Current Bloomberg Beta	11.28%	11.26%	11.23%
Long-term Avg. <i>Value Line</i> Beta	11.29%	11.27%	11.24%

C. Bond Yield Risk Premium Analysis

Q. Please describe your BYRP analysis.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for vertically integrated electric utilities as the historical measure of the cost of equity to determine the risk premium.

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1 **Q. What is the fundamental relationship between the equity risk premium and interest**
2 **rates?**

3 A. It is important to recognize both academic literature and market evidence indicating that
4 the equity risk premium (as used in this approach) is inversely related to the level of interest
5 rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa).
6 Consequently, it is important to develop an analysis that: (1) reflects the inverse
7 relationship between interest rates and the equity risk premium; and (2) relies on recent
8 and expected market conditions. The analysis presented in Exhibit A-14 (AEB-1),
9 Schedule D-5, pages 22-25 establishes that relationship using a regression of the risk
10 premium as a function of Treasury bond yields. When the authorized ROEs serve as the
11 measure of required equity returns and the long-term Treasury bond yield is defined as the
12 relevant measure of interest rates, the risk premium is the difference between those two
13 points.³⁴

14 **Q. Is the BYRP analysis relevant to investors?**

15 A. Yes. Investors are aware of authorized ROEs in other jurisdictions and they consider those
16 awards as a benchmark for a reasonable level of equity returns for utilities of comparable
17 risk operating in other jurisdictions. Because my BYRP analysis is based on authorized
18 ROEs for utility companies relative to corresponding Treasury yields, it provides relevant

³⁴ See *e.g.*, S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93," *Managerial and Decision Economics*, Vol. 19, No. 2, March 1998 (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). See also, Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66.

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1 information to assess the return expectations of investors in the current interest rate
2 environment.

3 **Q. What did your BYRP analysis reveal?**

4 A. As shown in Figure 9, from January 1980 through March 2025, there was a strong
5 negative relationship between risk premia and interest rates. To estimate that relationship,
6 I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year
U.S. Treasury bonds)

a = intercept term

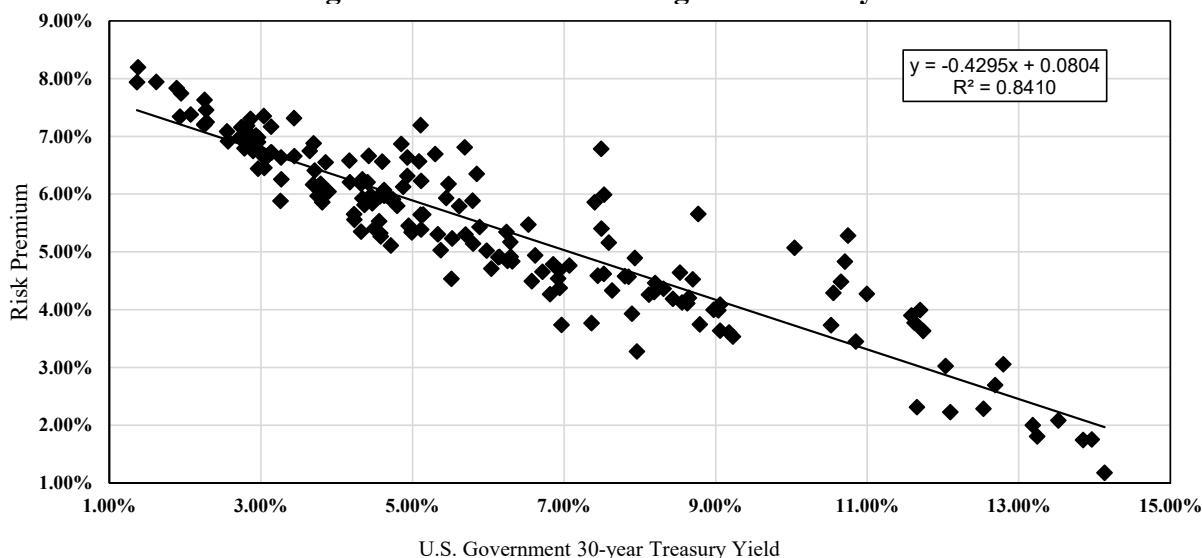
b = slope term

T = 30-year U.S. Treasury bond yield

7 Data regarding authorized ROEs were derived from all vertically integrated electric utility
8 rate cases over this period as reported by Regulatory Research Associates (“RRA”).³⁵ The
9 equation’s coefficients are statistically significant at the 99.00% level.

³⁵ The data was screened to eliminate limited issue rider cases, transmission-only cases, distribution-only cases and cases that were silent with respect to the authorized ROE.

Figure 9: Risk Premium Regression Analysis



Q. What are the results of your BYRP analysis?

A. Figure 10 below presents the results of my BYRP analysis, which is also presented in more detail in Exhibit A-14, (AEB-1), Schedule D-5, page 22.

Figure 10: BYRP Results

	30-Year Treasury Bond Yield		
	Current 30-Day Average	Near-Term Projected	Long-Term Projected
Bond Yield Risk Premium ROE	10.67%	10.62%	10.49%

Q. How did the results of the BYRP inform your recommended ROE for Consumers Energy?

A. I consider the results of the BYRP analysis in setting my recommended ROE for Consumers Energy. As noted above, investors consider the ROE determination by a regulator when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The BYRP analysis considers this comparison by

1 estimating the return expectations of investors based on the current and past authorized
2 ROEs of U.S. vertically integrated electric utilities.

3 **VIII. REGULATORY AND BUSINESS RISKS**

4 **Q. Do the results of the cost of equity analyses alone provide an appropriate estimate of**
5 **the cost of equity for the Company?**

6 A. No. These results provide only a range of the appropriate estimate of the Company's cost
7 of equity. Several additional factors impact the Company's overall risk profile relative to
8 the proxy group and must be considered when determining where the Company's cost of
9 equity falls within the range of analytical results. These risk factors are discussed below.

10 **A. Flotation Cost**

11 **Q. What are flotation costs?**

12 A. Flotation costs are the costs associated with the sale of new issues of common stock. These
13 costs include out-of-pocket expenditures for preparation, filing, underwriting, and other
14 issuance costs.

15 **Q. Why is it important to consider flotation costs in the allowed ROE?**

16 A. A regulated utility must have the opportunity to earn an ROE that is both competitive and
17 compensatory to attract and retain new investors. To the extent that a company is denied
18 the opportunity to recover prudently incurred flotation costs, actual returns will fall short
19 of expected (or required) returns, thereby diluting equity share value.

20 **Q. Are flotation costs part of the utility's invested costs or part of the utility's expenses?**

21 A. Flotation costs are part of the invested costs of the utility, which are properly reflected on
22 the balance sheet under "paid in capital." They are not current expenses, and, therefore,

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1 are not reflected on the income statement. Rather, like investments in rate base or the
2 issuance costs of long-term debt, flotation costs are incurred over time. As a result, the
3 great majority of a utility's flotation cost is incurred prior to the test year but remains part
4 of the cost structure that exists during the test year and beyond, and as such, should be
5 recognized for ratemaking purposes. Therefore, it is irrelevant whether an issuance occurs
6 during the test year or is planned for the test year because failure to allow recovery of past
7 flotation costs may deny Consumers Energy the opportunity to earn its required rate of
8 return in the future.

9 **Q. Can you provide an example of why a flotation cost adjustment is necessary to**
10 **compensate investors for the capital they have invested?**

11 A. Yes. Suppose CMS issues stock with a value of \$100, and an equity investor invests \$100
12 in CMS in exchange for that stock. Further suppose that, after paying the flotation costs
13 associated with the equity issuance, which include fees paid to underwriters and attorneys,
14 among others, CMS ends up with only \$97 of issuance proceeds, rather than the \$100 the
15 investor contributed. CMS invests that \$97 in plant used to serve its customers, which
16 becomes part of rate base. Absent a flotation cost adjustment, the investor will thereafter
17 earn a return on only the \$97 invested in rate base, even though she contributed \$100.
18 Making a small flotation cost adjustment gives the investor a reasonable opportunity to
19 earn the authorized return, rather than the lower return that results when the authorized
20 return is applied to an amount less than what the investor contributed.

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1 **Q. Is the date of CMS' last issued common equity important in the determination of**
2 **flotation costs?**

3 A. No. As shown in Exhibit A-14 (AEB-1), Schedule D-5, page 26, CMS closed on equity
4 issuances of approximately \$298 million and \$282 million (for a total of 55.78 million
5 shares of common stock) in October 2004 and March 2005, respectively. The vintage of
6 the issuance, however, is not particularly important because the investor suffers a shortfall
7 in every year that she should have a reasonable opportunity to earn a return on the full
8 amount of capital that she has contributed. Returning to my earlier example, the investor
9 who contributed \$100 is entitled to a reasonable opportunity to earn a return on \$100 not
10 only in the first year after the investment, but in every subsequent year in which she has
11 the \$100 invested. Leaving aside depreciation, which is dealt with separately, there is no
12 basis to conclude that the investor is entitled to earn a return on \$100 in the first year after
13 issuance, but thereafter is entitled to earn a return on only \$97. As long as the \$100 is
14 invested, the investor should have a reasonable opportunity to earn a return on the entire
15 amount.

16 **Q. Is the need to consider flotation costs eliminated because Consumers Energy is a**
17 **wholly-owned subsidiary of CMS?**

18 A. No. Although Consumers Energy is a wholly-owned subsidiary of CMS, it is appropriate
19 to consider flotation costs because wholly-owned subsidiaries receive equity capital from
20 their parent and provide returns on the capital that roll up to the parent, which is designated
21 to attract and raise capital based upon the returns of those subsidiaries. To deny recovery
22 of issuance costs associated with the capital that is invested in the subsidiaries ultimately

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1 penalizes the investors that fund the utility operations and could inhibit the utility's ability
2 to obtain new equity capital at a reasonable cost.

3 **Q. Is the need to consider flotation costs recognized by the academic and financial**
4 **communities?**

5 A. Yes. The need to reimburse shareholders for the lost returns associated with equity
6 issuance costs is recognized by the academic and financial communities in the same spirit
7 that investors are reimbursed for the costs of issuing debt. This treatment is consistent with
8 the philosophy of a fair rate of return. According to Dr. Shannon Pratt:

9 Flotation costs occur when new issues of stock or debt are
10 sold to the public. The firm usually incurs several kinds of
11 flotation or transaction costs, which reduce the actual
12 proceeds received by the firm. Some of these are direct out-
13 of-pocket outlays, such as fees paid to underwriters, legal
14 expenses, and prospectus preparation costs. Because of this
15 reduction in proceeds, the firm's required returns on these
16 proceeds equate to a higher return to compensate for the
17 additional costs. Flotation costs can be accounted for either
18 by amortizing the cost, thus reducing the cash flow to
19 discount, or by incorporating the cost into the cost of capital.
20 Because flotation costs are not typically applied to operating
21 cash flow, one must incorporate them into the cost of
22 capital.³⁶

23 **Q. How did you calculate the flotation costs for CMS?**

24 A. My flotation cost calculation is based on the costs of issuing equity that were incurred by
25 CMS in its two most recent common equity issuances. That flotation cost percentage is
26 then applied to the proxy group in the DCF analysis to estimate the impact on the cost of
27 equity associated with flotation costs. As shown in Exhibit A-14 (AEB-1), Schedule D-5,

³⁶ Shannon P. Pratt, *Cost of Capital Estimation and Applications* (2nd ed. 2002), at 220-221.

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1 page 26, based on the flotation costs previously incurred by CMS, the average impact on
2 the proxy group's cost of equity is 14 basis points (*i.e.*, 0.14%).

3 **Q. Do your final cost of equity results include an adjustment for flotation cost recovery?**

4 A. No. While the final ROE results do not incorporate an explicit adjustment for flotation
5 costs, I have considered the effect of flotation costs, along with the other risk factors present
6 for the Company, in determining where, within the range of analytical results, my
7 recommended ROE for the Company should fall.

8 **B. Capital Expenditures**

9 **Q. What are the Company's projected capital expenditure requirements over the next**
10 **few years?**

11 A. As of December 31, 2024, the Company had net electric utility plant of approximately
12 \$11.4 billion,³⁷ and the Company currently projects capital expenditures for 2025 through
13 2029 of approximately \$13.7 billion,³⁸ which represent approximately 120.0% of its
14 current net electric utility plant.

15 **Q. How do Consumers Energy's capital expenditure requirements compare to those of**
16 **the proxy group companies?**

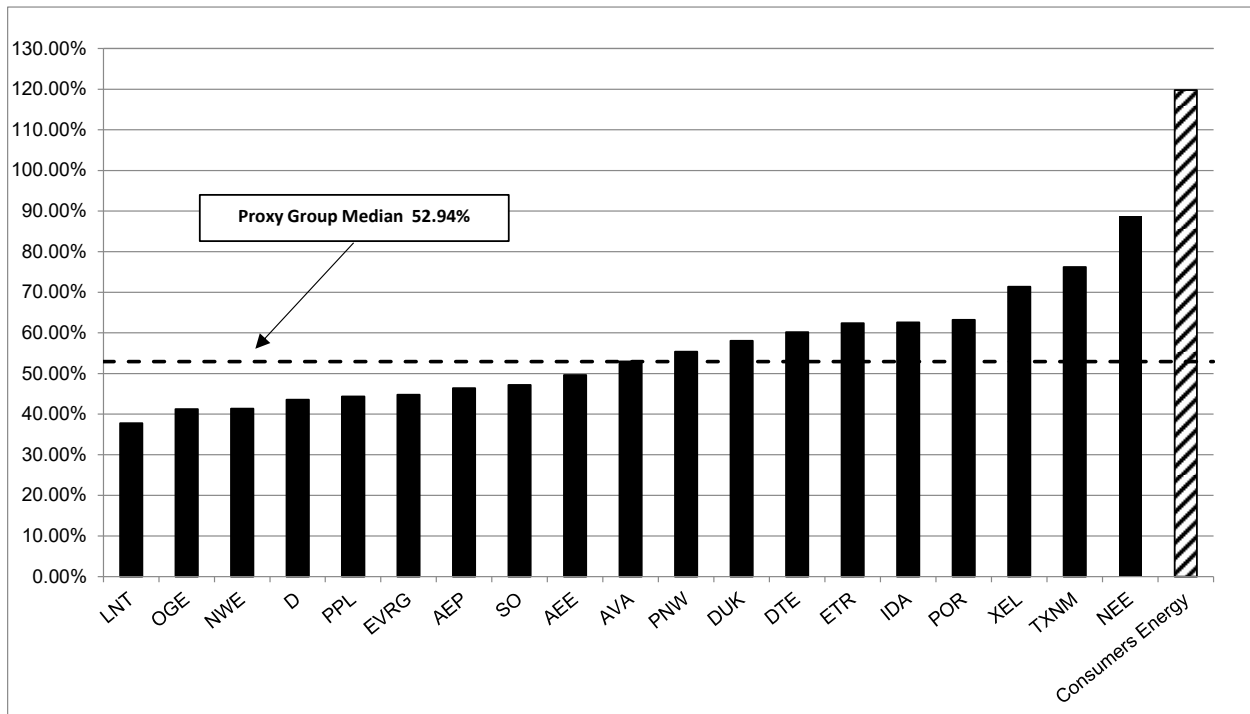
17 A. Figure 11 (see also Exhibit A-14 (AEB-1), Schedule D-5, pages 27-29) shows the ratio of
18 expected capital expenditures to net utility plant for Consumers Energy and each of the
19 companies in the proxy group. This is done by dividing each company's projected capital
20 expenditures for the period from 2025 through 2029 by its total net utility plant as of

³⁷ Company provided.

³⁸ Company provided.

December 31, 2024. As shown, Consumers Energy's ratio of capital expenditures as a percentage of net utility plant is significantly higher than companies in the proxy group as it is 2.26 times higher than the median for the proxy group companies.

Figure 11: Comparison of Capital Expenditures



Q. How is the Company's risk profile affected by its substantial capital expenditure requirements?

A. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

1 **Q. Do credit rating agencies recognize the risks associated with significant capital**
2 **expenditures?**

3 A. Yes. From a credit perspective, the additional pressure on cash flows associated with high
4 levels of capital expenditures exerts corresponding pressure on credit metrics and,
5 therefore, credit ratings. To that point, S&P explains the importance of regulatory support
6 for large capital projects:

7 When applicable, a jurisdiction's willingness to support
8 large capital projects with cash during construction is an
9 important aspect of our analysis. This is especially true
10 when the project represents a major addition to rate base and
11 entails long lead times and technological risks that make it
12 susceptible to construction delays. Broad support for all
13 capital spending is the most credit-sustaining. Support for
14 only specific types of capital spending, such as specific
15 environmental projects or system integrity plans, is less so,
16 but still favorable for creditors. Allowance of a cash return
17 on construction work-in-progress or similar ratemaking
18 methods historically were extraordinary measures for use in
19 unusual circumstances, but when construction costs are
20 rising, cash flow support could be crucial to maintain credit
21 quality through the spending program. Even more favorable
22 are those jurisdictions that present an opportunity for a
23 higher return on capital projects as an incentive to
24 investors.³⁹

25 Recently, S&P evaluated the capital expenditure trends in the utility sector, noting that the
26 balance between operating with negative discretionary cash flow from operations offset by
27 reliable access to capital markets for financing may be tested through ever-increasing
28 capital expenditure requirements as a result of the transformation of the energy sector

³⁹ S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

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1 through the focus on low/no carbon generation, electrification, and the replacement of
2 aging infrastructure:

3 We expect rising capital spending and increasing cash flow
4 deficits that are not sufficiently funded in a credit-supportive
5 manner will continue to pressure the industry's financial
6 performance. Its average funds from operations (FFO) to
7 debt was about 15% in 2021 and has gradually fallen to
8 about 13.5%, primarily reflecting rising leverage (see
9 chart 20). Given our expectations for continued increasing
10 capital spending over the next decade, we expect financial
11 performance and credit quality will continue to be
12 pressured.⁴⁰

13 Therefore, to the extent that Consumers Energy's rates do not permit the opportunity to
14 recover its capital investments on a regular and timely basis, the Company will face
15 increased recovery risk and thus increased pressure on its credit metrics.

16 **Q. Does the Company currently have a capital tracking mechanism to recover the costs**
17 **associated with its capital expenditures plan between rate cases?**

18 A. Yes. Consumers Energy does currently have limited recovery of capital expenditures
19 through the Renewable Energy Plan ("REP") and Power Supply Cost Recovery ("PSCR")
20 that together allow for recovery of capital and operating costs associated with Consumers
21 Energy's compliance with its renewable portfolio standard. Additionally, the Company is
22 requesting a Distribution Infrastructure Recovery Mechanism in this proceeding to recover
23 a two-year period beginning May 1, 2026 consistent with the start of the test year. While
24 the Company's proposed infrastructure tracking mechanism if approved as well as the REP

⁴⁰ S&P Global Ratings, "Industry Credit Outlook 2025, North American Regulated Utilities: Capex and climate change pressures credit quality," January 14, 2025, at 10.

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1 and PSCR provide for timely recovery of qualifying investments, Consumers Energy
2 would still depend on rate case filings for a significant position of its capital cost recovery.

3 **Q. Are the proposed infrastructure recovery mechanism as well as the REP and PSCR**
4 **sufficiently risk reducing to adjust the ROE?**

5 A. No. The cost of equity analysis is conducted using market data for a proxy group of
6 comparable companies and necessarily considers the relative risk of the subject company
7 and the proxy group in the final determination of the ROE. Accordingly, although
8 Consumer Energy's use of the REP and PSCR as well as the proposed infrastructure
9 recovery mechanism if approved may reduce its own risk, the appropriate point of
10 comparison is whether those tracking mechanisms are reducing risk relative to the proxy
11 group, which I discuss below.

12 **Q. How do the Company's existing and proposed trackers compare with the capital**
13 **investment and other trackers that have been implemented by the proxy companies?**

14 A. As shown in Exhibit A-14 (AEB-1), Schedule D-5, pages 30-31, approximately 72% of the
15 companies in the proxy group currently have mechanisms for some form of capital cost
16 recovery in place. Because such clauses have become commonplace in utility regulation,
17 the Company's proposed infrastructure recovery mechanism if approved as well as the REP
18 and PSCR do not reduce the Company's risk vis-à-vis that of the proxy group. However,
19 because of the limited recovery of capital investments through both the REP and PSCR, if
20 the Company's proposed infrastructure mechanism is not approved, it is likely that other
21 jurisdictions have more expansive cost recovery mechanisms.

1 **Q. What are your conclusions regarding the effect of the Company's capital spending**
2 **requirements on its risk profile and cost of capital?**

3 A. Consumers Energy has a significantly higher ratio of projected capital expenditure to net
4 utility plant relative to the proxy group over the next five years. Additionally, the
5 Company's ability to recover capital costs on a timely basis through both the REP and
6 PSCR is limited. The Company is requesting an infrastructure recovery mechanism to
7 recover qualifying distribution capital investment; however, the Company would still
8 depend on rate case filings for capital cost recovery. Further, as shown in Exhibit A-14
9 (AEB-1), Schedule D-5, pages 30-31, a majority of the operating subsidiaries of the proxy
10 group have implemented capital tracking mechanisms to recover capital expenditures.
11 Therefore, the Company's risk profile regarding capital expenditures would be similar to
12 the proxy group if the Company's proposed infrastructure recovery mechanism is
13 approved. However, if the Company's proposed infrastructure recovery mechanism is not
14 approved, Consumers Energy's significant capital expenditures plan and limited ability to
15 recover the capital investment on an as-incurred basis result through both the REP and
16 PSCR would result in a risk profile is greater than that of the proxy group and supports an
17 ROE toward the higher end of the reasonable range of ROEs.

18 **C. Regulatory Risk**

19 **Q. How does the regulatory environment affect investors' risk assessments?**

20 A. The ratemaking process is premised on the principle that, for investors and companies to
21 commit the capital needed to provide safe and reliable utility service, the subject utility
22 must have the opportunity to recover the return of, and the market-required return on,

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1 invested capital. Regulatory commissions recognize that because utility operations are
2 capital intensive, their decisions should enable the utility to attract capital at reasonable
3 terms, and that doing so balances the long-term interests of investors and customers.
4 Utilities must finance their operations and thus require the opportunity to earn a reasonable
5 return on their invested capital to maintain their financial profiles. The Company is no
6 exception. Therefore, the regulatory environment is one of the most important factors
7 considered in both debt and equity investors' risk assessments.

8 From the perspective of debt investors, the authorized return should enable the
9 utility to generate the cash flow needed to meet its near-term financial obligations, make
10 the capital investments needed to maintain and expand its systems, and maintain the
11 necessary levels of liquidity to fund unexpected events. This financial liquidity must be
12 derived not only from internally-generated funds, but also by efficient access to capital
13 markets. Moreover, because fixed income investors have many investment alternatives,
14 even within a given market sector, a utility's financial profile must be adequate on a relative
15 basis to ensure its ability to attract capital under a variety of economic and financial market
16 conditions.

17 Equity investors require that the authorized return be adequate to provide a
18 risk-comparable return on the equity portion of the utility's capital investments. Because
19 equity investors are the residual claimants on the utility's cash flows (*i.e.*, the equity return
20 is subordinate to interest payments), they are particularly concerned with the strength of
21 regulatory support and its effect on future cash flows.

1 **Q. Do credit rating agencies consider regulatory risk in establishing a company's credit**
2 **rating?**

3 A. Yes. Both S&P and Moody's consider the overall regulatory framework in establishing
4 credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory
5 framework; (2) the ability to recover costs and earn returns; (3) diversification; and
6 (4) financial strength, liquidity and key financial metrics. Of these criteria, regulatory
7 framework and the ability to recover costs and earn returns are each given a broad rating
8 factor of 25.00%. Therefore, Moody's assigns regulatory risk a 50.00% weighting in the
9 overall assessment of business and financial risk for regulated utilities.⁴¹

10 S&P also identifies the regulatory framework as an important factor in credit ratings
11 for regulated utilities, stating: "we assess regulatory advantage because the influence of the
12 regulatory framework and regime is of critical importance. It defines the environment in
13 which a utility operates and has a significant bearing on a utility's financial performance."⁴²
14 S&P identifies four specific factors that it uses to assess the credit implications of the
15 regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability;
16 (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory
17 independence and insulation.⁴³

⁴¹ Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 2.

⁴² Standard & Poor's Global Ratings, "Sector-Specific Corporate Methodology," April 4, 2024, at 147.

⁴³ *Id.*

1 **Q. How does the regulatory environment in which a utility operates affect its access to**
2 **and cost of capital?**

3 A. The regulatory environment can significantly affect both the access to and cost of capital
4 in several ways. First, the proportion and cost of debt capital available to utility companies
5 are influenced by the rating agencies' assessment of the regulatory environment. As noted
6 by Moody's, "[u]tility rates are set in a political/regulatory process rather than a
7 competitive or free-market process; thus, the regulatory framework is a key determinant of
8 the credit quality of a utility."⁴⁴ Moody's further highlighted the relevance of a stable and
9 predictable regulatory environment to a utility's credit quality, noting: "[t]he regulatory
10 framework is important because it provides the basis for decisions that affect utilities,
11 including rate-setting as well as the consistency and predictability of regulatory decision-
12 making."⁴⁵

13 **Q. Have you conducted an analysis to compare the cost recovery mechanisms of**
14 **Consumers Energy to the cost recovery mechanisms approved in the jurisdictions in**
15 **which the companies in your proxy group operate?**

16 A. Yes. I have evaluated the regulatory framework in Michigan based on three factors that
17 are important in terms of providing a regulated utility a reasonable opportunity to earn its
18 authorized ROE: (1) test year convention (*i.e.*, forecast vs. historical); (2) use of rate design
19 or other mechanisms that mitigate volumetric risk and stabilize revenue; and (3) prevalence

⁴⁴ Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 8.

⁴⁵ *Id.*

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of capital cost recovery between rate cases. Each are described below and are summarized in Exhibit A-14 (AEB-1), Schedule D-5, pages 30-31.

Test Year Convention: Consumers Energy uses a forecasted test year, and similarly, approximately 51% of the operating companies held by the proxy group provide service in jurisdictions that use a fully or partially forecasted test year. Forecast test years have been relied on for several years and produce cost estimates that are more reflective of future costs which results in more accurate recovery of incurred costs and mitigates the regulatory lag associated with historical test years.

Volumetric Risk: Consumers Energy does not currently have protection against volumetric risk. However, approximately 60% of the utility operating subsidiaries of the proxy group companies have some form of revenue stabilization through either decoupling, formula-based rates, and/or straight-fixed variable rate design that allow them to break the link between customer usage and revenues.

Capital Cost Recovery: As discussed above, Consumers Energy has a capital tracking mechanism available under its REP and PSCR to recover limited capital investment costs between rate cases related to compliance with its renewable portfolio standard and is requesting approval for an infrastructure recovery mechanism that would allow the Company to recovery distribution capital investments. Similarly, approximately 71% of the utility operating subsidiaries of the proxy group companies have some form of capital cost recovery mechanism.

Q. How does RRA evaluate the regulatory environment in each jurisdiction?

A. RRA evaluates the regulatory environment from an investor perspective, considering the relative regulatory risk associated with ownership of securities issued by the companies that are regulated in each jurisdiction. RRA considers several factors that affect the regulatory process, including gubernatorial, legislative and court activity, rate case decisions and other regulatory decisions, and information obtained through contact with commissioners, staff, utilities, and government outreach.

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1 **Q. Has RRA provided recent commentary regarding its regulatory ranking for**
2 **Michigan?**

3 **A. In August 2024, RRA lowered its regulatory ranking of Michigan from “Above Average/3”**
4 **to “Average/1,” noting the following:**

5 Regulatory Research Associates, a group within S&P Global
6 Commodity Insights, views the regulatory climate in
7 Michigan as somewhat constructive from an investor
8 perspective. On July 31, 2024, RRA reduced its ranking of
9 Michigan regulation to Average/1 from Above Average/3.
10 While the jurisdiction remains more constructive than
11 average from an investor viewpoint, ***the outcomes of certain***
12 ***recent rate proceedings could indicate a tightening in the***
13 ***regulatory climate.*** RRA had placed the state on watch
14 following a 2022 rate case decision in which the Michigan
15 Public Service Commission (PSC) authorized DTE Electric
16 Co. (DTE-E) an increase in rates that was less than 10% of
17 that requested, but did not lower the ranking at that time. At
18 the time RRA viewed the decisions to be an anomaly, as a
19 large part of the revenue requirement difference stemmed
20 from reliance on a higher post-COVID sales forecast than
21 the utility had used in its revenue requirement calculations.
22 DTE-E has had two rate cases decided since then, and while
23 generally more constructive, the company requested
24 rehearing of two issues with respect to its latest case decided
25 Jan. 23, 2025. The commission denied the request for
26 rehearing. DTE-E is not the only company that has faced
27 challenges in recent rate proceedings before the PSC. In a
28 July 2, 2024 electric rate decision for Indiana Michigan
29 Power Co.(IMP), the commission authorized the company a
30 rate increase that was about half what the company requested
31 and kept its authorized ROE unchanged despite recent
32 increases in interest rates. While the approved ROEs for both
33 DTE-E and IMP remain above prevailing industry averages,
34 they compare less favorably to those averages, which have
35 risen, albeit modestly, in recent periods. The commission,
36 nevertheless, does have several constructive practices have
37 been in place: a streamlined rate case process; a framework
38 for the utilization of forecast test years to reduce regulatory
39 lag; and a framework that permits a cash return on certain
40 construction work in progress, thereby reducing the

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1 uncertainty of cost recovery. Retail competition for electric
2 generation is in place but is limited, and attempts to raise this
3 limit have not been successful. Electric utilities have
4 retained their generation assets, and customers who do not
5 select a competitive supplier receive service on a regulated,
6 traditional cost-of-service basis. Adjustment mechanisms
7 are in place for fuel costs for customers served under
8 bundled service. However, the courts have ruled against the
9 authorization of revenue decoupling mechanisms for electric
10 utilities. In the gas industry, the major local distribution
11 companies have instituted programs that allow all retail
12 customers to choose their gas supplier, and modest small-
13 customer switching has occurred. The gas companies utilize
14 periodic gas cost recovery mechanisms, and the PSC has
15 authorized revenue decoupling mechanisms for certain gas
16 utilities. Michigan's regulatory and political environments
17 continue to support significant capital investments and
18 timely recovery of these costs. RRA now accords Michigan
19 regulation an Average/1 ranking.⁴⁶

20 Additionally, Company witness Bleckman's direct testimony provides additional detail on
21 the credit rating agencies' assessment of Michigan's regulatory environment.

22 **Q. What are your conclusions regarding the perceived risks related to the regulatory**
23 **environment in Michigan?**

24 A. As discussed throughout this section of my testimony, both Moody's and S&P have
25 identified the supportiveness of the regulatory environment as an important consideration
26 in developing their overall credit ratings for regulated utilities. Considering the regulatory
27 adjustment mechanisms including assuming the Company's proposed infrastructure
28 recovery mechanism is approved, many of the companies in the proxy group have slightly
29 more timely cost recovery between rate proceedings than Consumers Energy has in
30 Michigan. While my analysis assumes that the Company's proposed infrastructure

⁴⁶ Regulatory Research Associates, Profile of Michigan Public Service Commission, accessed April 22, 2025.

1 recovery mechanism will be approved, the cost recovery risk of Consumers Energy would
2 increase relative to the proxy group if the Commission does not approve the Company's
3 proposal.

4 **IX. CONCLUSION AND RECOMMENDATION**

5 **Q. What is your conclusion regarding a fair ROE for Consumers Energy?**

6 A. Figure 12 summarizes the results of my cost of equity analyses. Based on these results, the
7 qualitative analyses presented in my direct testimony, the business and financial risks of
8 Consumers Energy compared to the proxy group, and current and prospective conditions
9 in capital markets, it is my view that an ROE of 10.25% is reasonable and would fairly
10 balance the interests of customers and shareholders.

11 **Q. Will the capital structure and ROE authorized in this proceeding affect the**
12 **Company's access to capital at reasonable rates?**

13 A. Yes. The level of earnings authorized by the Commission directly affects the Company's
14 ability to fund its operations with internally-generated funds. Both bond investors and
15 rating agencies expect a significant portion of ongoing capital investments to be financed
16 with internally-generated funds. In addition, it is important to recognize that because a
17 utility's investment horizon is very long, investors require the assurance of a sufficiently
18 high return to satisfy the long-term financing requirements of the assets placed into service.
19 Those assurances, which often are measured by the relationship between internally-
20 generated cash flows and debt (or interest expense), depend quite heavily on the capital
21 structure. Therefore, both the ROE and capital structure are very important to debt and
22 equity investors, particularly given the capital market conditions discussed previously.

Company witness Bleckman's direct testimony explains the effect of the Company's authorized ROE and Equity ratio on credit quality.

Figure 12: Summary of Analytical Results

<i>Constant Growth DCF</i>			
	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	8.92%	10.24%	11.18%
90-Day Avg. Stock Price	9.06%	10.38%	11.32%
180-Day Avg. Stock Price	9.16%	10.47%	11.42%
Average	9.05%	10.36%	11.31%
Median Results:			
30-Day Avg. Stock Price	9.47%	10.07%	10.77%
90-Day Avg. Stock Price	9.62%	10.27%	10.88%
180-Day Avg. Stock Price	9.79%	10.43%	11.01%
Average	9.63%	10.26%	10.89%
 <i>CAPM / ECAPM / Bond Yield Risk Premium</i>			
	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current <i>Value Line</i> Beta	12.18%	12.18%	12.17%
Current Bloomberg Beta	10.85%	10.83%	10.78%
Long-term Avg. <i>Value Line</i> Beta	10.85%	10.83%	10.79%
ECAPM:			
Current <i>Value Line</i> Beta	12.28%	12.28%	12.27%
Current Bloomberg Beta	11.28%	11.26%	11.23%
Long-term Avg. <i>Value Line</i> Beta	11.29%	11.27%	11.24%
Bond Yield Risk Premium	10.67%	10.62%	10.49%

Q. Does this conclude you direct testimony?

A. Yes.



Ann E. Bulkley
PRINCIPAL

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With more than 25 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas and water utility sectors, including valuation of regulated and unregulated utility assets, cost of capital, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in nearly 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation



EDUCATION

- **Boston University**
MA in Economics
- **Simmons College**
BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
Senior Vice President
Vice President
Assistant Vice President
Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
Project Manager
- **Reed Consulting Group (1995-1997)**
Consultant- Project Manager
- **Cahners Publishing Company (1995)**
Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies



Analysis and program development to address residual energy supply and/or provider of last resort obligations

- Stranded costs assessment and recovery
Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff and prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.



Conducted a strategic review of the acquisition of nuclear generation assets. Review included the evaluation of the operating costs of the facilities and the long-term liabilities associated with the assets including the decommissioning of the assets.

- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approach. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Conducted a valuation of regulated utility assets for the fair value rate base estimate used in electric rate proceedings in Indiana.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:





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Preparation of feasibility studies for bond issuances for municipal and district steam clients.

- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.



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BULKLEY TESTIMONY LISTING

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
UNS Gas	11/24	UNS Gas	Docket No. G-04204A-24-0237	Return on Equity
Southwest Gas Corporation	02/24	Southwest Gas Corporation	Docket No. G-01551A-23-0341	Return on Equity
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
PacifiCorp, d/b/a Pacific Power	5/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Colorado Public Utilities Commission				
Public Service Company of Colorado	01/24	Public Service Company of Colorado	Docket No. 24AL-___G	Return on Equity
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
United Illuminating	11/12/24	United Illuminating	Docket No. 24-10-04	Return on Equity
The Southern Connecticut Gas Company	11/23	The Southern Connecticut Gas Company	Docket No. 23-11-02	Return on Equity
Connecticut Natural Gas Corporation	11/23	Connecticut Natural Gas Corporation	Docket No. 23-11-02	Return on Equity
Connecticut Water Company	10/23	Connecticut Water Company	Docket No. 23-08-32	Return on Equity
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-____	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-____	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-____	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				
PacifiCorp d/b/a Rocky Mountain Power	05/24	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-24-04	Return on Equity



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-24-04	Return on Equity
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
Illinois American Water	01/24	Illinois American Water	Docket No. 24-0097	Return on Equity
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				
Ohio Valley Gas Corporation and Ohio Valley Gas, Inc.	02/24	Ohio Valley Gas Corporation and Ohio Valley Gas, Inc.	Cause No. 46011	Return on Equity
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	12/23	Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	IURC Cause No. 45990	Return on Equity
Indiana Michigan Power Co.	08/23	Indiana Michigan Power Co.	IURC Cause No. 45933	Return on Equity
Indiana American Water Company	03/23	Indiana and Michigan American Water Company	IURC Cause No. 45870	Return on Equity
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				
Iowa-American Water Company	04/24	Iowa-American Water Company	Docket No. RPU-2024-000_	Return on Equity
MidAmerican Energy Company	06/23	MidAmerican Energy Company	Docket No. RPU-2023-___	Return on Equity
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Evergy Kansas	04/23	Evergy Kansas	Docket No. 23-EKCE-775-RTS	Return on Equity
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Kentucky American Water Company	06/23	Kentucky American Water Company	Docket No. 2023-____	Return on Equity
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	11/23	Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	DPU 23-150	Return on Equity
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Consumers Energy	12/16/24	Consumers Energy	C-U-21806	Return on Equity
Upper Michigan Energy Resources Corporation	05/24	Upper Michigan Energy Resources Corporation	Case No. U-21541	Return on Equity



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Michigan Gas Utilities Corporation	03/24	Michigan Gas Utilities Corporation	Case No. U-21540	Return on Equity
Indiana Michigan Power Co.	09/23	Indiana Michigan Power Co.	Case No. U-21461	Return on Equity
Michigan Gas Utilities Corporation	03/23	Michigan Gas Utilities Corporation	Case No. U-21366	Return on Equity
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
ALLETE, Inc. d/b/a Minnesota Power	11/23	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-23-155	Return on Equity
CenterPoint Energy Resources	11/23	CenterPoint Energy Resources	D-G-008/GR-23-173	Return on Equity
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Ameren Missouri	09/24	Ameren Missouri	File No. GR-2024-0369	Return on Equity
Missouri American Water Company	07/24	Missouri American Water Company	WR-2024-0320	Return on Equity
Ameren Missouri	06/24	Ameren Missouri	File No. ER-2024-0319	Return on Equity
Evergy Missouri West	02/24	Evergy Missouri West	File No. ER-2024-0189	Return on Equity
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	01/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
Evergy Missouri Metro	01/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	7/24	Montana-Dakota Utilities Co.	D2024-05-061	Return on Equity
Montana-Dakota Utilities Co.	11/22	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
Public Utilities Commission of Nevada				
Nevada Power Company d/b/a NV Energy	02/25	Nevada Power Company d/b/a NV Energy	25-02016	Return on Equity
Sierra Pacific Power Company d/b/a NV Energy	02/24	Sierra Pacific Power Company d/b/a NV Energy	24-02026	Return on Equity
Nevada Power Company d/b/a NV Energy	06/23	Nevada Power Company d/b/a NV Energy	23-06007	Return on Equity
Nevada Power Company d/b/a NV Energy	03/23	Nevada Power Company d/b/a NV Energy	22-03028	Merger benefits
New Hampshire - Board of Tax and Land Appeals				
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Liberty Utilities (EnergyNorth Natural Gas)	07/23	Liberty Utilities (EnergyNorth Natural Gas)	Docket No. DG 23-067	Return on Equity



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Liberty Utilities (Granite State Electric)	05/23	Liberty Utilities (Granite State Electric)	Docket No. DE 23-039	Return on Equity
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
New Jersey American Water Company, Inc.	02/24	New Jersey American Water Company, Inc.	WR2401056	Return on Equity
Elizabethtown Gas Company	2/24	Elizabethtown Gas Company	GR24020158	Return on Equity
Public Service Electric and Gas Company	12/23	Public Service Electric and Gas Company	ER23120924 GR23120925	Return on Equity
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity
New Mexico Public Regulation Commission				



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
Liberty Utilities (New York Water)	5/23	Liberty Utilities (New York Water)	Case 23-W-0235	Return on Equity
New York State Electric and Gas Company	05/22	New York State Electric and Gas Company	22-E-0317 22-G-0318 22-E-0319	Return on Equity
Rochester Gas and Electric		Rochester Gas and Electric	22-G-0320	
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company	05/19	New York State Electric and Gas Company	19-E-0378 19-G-0379 19-E-0380	Return on Equity
Rochester Gas and Electric		Rochester Gas and Electric	19-G-0381	



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
Otter Tail Power Company	11/23	Otter Tail Power Company	Case No. PU-23-____	Return on Equity
Montana-Dakota Utilities Co.	11/23	Montana-Dakota Utilities Co.	Case No. PU-23-____	Return on Equity
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/23	Oklahoma Gas & Electric	Cause No. PUD2023-000087	Return on Equity
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
PacifiCorp d/b/a Pacific Power & Light	02/24	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-433	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	11/23	Pennsylvania-American Water Company	Docket No. R-2023-3043189 (water) Docket No. R-2023-3043190 (wastewater)	Return on Equity
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Tennessee Public Utility Commission				
Tennessee American Water Company	04/24	Tennessee American Water Company	Docket No.24-00032	Return on Equity
Texas Public Utility Commission				
Electric Transmission Texas LLC	02/25	Electric Transmission Texas LLC	Docket No. 57518	Return on Equity
CenterPoint Energy Houston	03/24	CenterPoint Energy Houston	D-56211	Return on Equity
AEP Texas	02/24	AEP Texas	D-56165	Return on Equity
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
Texas Railroad Commission				
CenterPoint Energy Entex and CenterPoint Energy Texas Gas	10/23	CenterPoint Energy Entex and CenterPoint Energy Texas Gas	2023 Texas Division Rate Case Case No. OS-23-00015513	Return on Equity
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	06/24	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 24-035-04	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/23	Virginia American Water Company, Inc.	Docket No. PUR-2023-00194	Return on Equity
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
Cascade Natural Gas Corporation	03/24	Cascade Natural Gas Corporation	Docket No. UG-240008	Return on Equity
Puget Sound Energy Inc.	02/24	Puget Sound Energy Inc.	Docket No. UE-240004 UG-240005	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	03/23	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-230172	Return on Equity
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	05/23	West Virginia American Water Company	Case No. 23-0383-W-42T	Return on Equity
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Power and Light	04/24	Wisconsin Power and Light	Docket No. 6680-UR-128	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/24	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-111	Return on Equity
Wisconsin Power and Light	05/23	Wisconsin Power and Light	Docket No. 6680-UR-124	Return on Equity



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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
Montana-Dakota Utilities Co.	10/24	Montana-Dakota Utilities Co.	Docket No. 30013-415-GR-24	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	08/24	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-671-ER-24	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	02/23	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-633-ER-23	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts

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)
electric and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

JESSICA R. BYROM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

JESSICA R. BYROM
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1 **Q. Please state your name and business address.**

2 A. My name is Jessica R. Byrom, and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

4 **Q. By whom are you employed and what is your present position?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
6 as Director of Customer Strategy.

7 **Q. Please review your educational background.**

8 A. I graduated from Michigan State University in 2008 with a Bachelor of Arts in International
9 Relations and in 2015 with a Master of Business Administration.

10 **Q. Please review your business experience.**

11 A. In 2009, I began full-time employment with Michigan State University, working primarily
12 in a human resources role during my tenure with the university. My role centered around
13 process optimization and management of the hiring, firing, and compliance investigation
14 processes for the department’s 4,000 part-time and nearly 500 full-time employees. In
15 2017, I began my career at Consumers Energy as a member of the Customer Operations
16 Strategy team. I was promoted to manager and eventual director of this team in March
17 2018. During my time with that team, I had the responsibility of working with the
18 Company’s business partners within the Customer Operations and Customer Experience
19 teams related to goal creation, data organization, process optimization, testimony creation
20 for rate cases, and the implementation of lean operating system framework. In September
21 2021, I took on the role of Director of Residential Demand Side Management, leading the
22 team that owns and manages the products within the Residential sector for Energy Waste

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1 Reduction (“EWR”) and Demand Response (“DR”). In June 2024, I took on the role of
2 Director of Customer Strategy.

3 In this position, I am responsible for the implementation of the Company’s lean
4 operating system within the Customer organization, working with business units to
5 improve Customer-related processes.

6 **Q. Have you previously testified before the Michigan Public Service Commission**
7 **(“MPSC” or the “Commission”)?**

8 A. Yes, I filed testimony on behalf of the Company in the following proceedings before the
9 Commission:

10 Case No. U-21233 2021 DR Reconciliation;

11 Case No. U-21205 2021 EWR Reconciliation;

12 Case No. U-21321 2024-2025 EWR Plan;

13 Case No. U-21410 2022 DR Reconciliation;

14 Case No. U-21647 2023 DR Reconciliation; and

15 Case No. U-21806 2024 Gas Rate Case.

16 **Q. What is the purpose of your direct testimony in this proceeding?**

17 A. The purpose of my direct testimony is to describe the Customer Experience and Operations
18 (“CX&O”) organization and how the work performed within this organization benefits the
19 Company’s residential and business electric customers. As part of my direct testimony,
20 I will address the operating and maintenance (“O&M”) expenses and capital investments
21 associated with executing this work in the test year ending April 30, 2027. I will also
22 address one item raised in the regression analysis of customer shutoffs sponsored by
23 Company witness Michael P. Kelly.

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Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-12 (JRB-1) Schedule B-5.3 Actual and Projected Capital Expenditures - Customer Experience & Operations; and

Exhibit A-53 (JRB-2)

Summary of Actual & Projected
O&M Expenses – Customer
Experience, Customer Operations:
Customer Interactions.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please describe Exhibit A-12 (JRB-1), Schedule B-5.3.

A. Exhibit A-12 (JRB-1), Schedule B-5.3, details the capital expenditures related to direct work within the CX&O organization, which totaled \$1.25 million in the historical year, \$693,000 projected in the bridge period, and \$1.87 million projected in the test year. This reflects a financial forecast based on the work plan and designated development activities within Analytics and Outreach, Customer Billing, and Credit and Assistance areas.

Please note that this testimony also discusses the Customer Information Technology (“IT”) project benefits related to the capital spend sponsored by IT Company witness Stacey H. Baker.

Q. Please describe Exhibit A-53 (JRB-2).

A. Exhibit A-53 (JRB-2) details the O&M expenses related to work within the CX&O organization, which totals approximately \$35,000,000 for the test year ending April 30, 2027.

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1 **Q. Please describe Exhibit A-53 (JRB-2) page 4.**

2 A. Exhibit A-53 (JRB-2), page 4, is a hypothetical illustration of the CX&O projected O&M
3 expenses based on inflation. This page is for illustrative purposes only and not intended to
4 represent how the Company has developed its projected CX&O O&M. Column (b) shows
5 the historical O&M expense. Column (c) shows the historical amount to which an inflation
6 rate or merit increase rate was applied. Columns (e) and (g) show the amounts to which a
7 hypothetical inflation rate or merit increase rate were applied for each bridge period,
8 respectively. Columns (d), (f), and (h) show the hypothetical merit and inflation increases
9 for each respective period. Because the Company does not develop the projected CX&O
10 O&M using inflation, it is necessary to include column (i), other adjustments. Column (i)
11 is simply the difference between the Company's actual projected O&M and what the O&M
12 would have been if the Company had used inflation to project CX&O O&M. Column (j)
13 is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i). The
14 expenses that I am supporting are based upon the projected expenses necessary to meet the
15 needs of the various projects and department operations planned in the test year and are not
16 based on applying an inflation rate to the historical O&M expenses.

17 **Q. Please describe how the CX&O budgets and how the projected O&M expenses are**
18 **developed.**

19 A. The budgets are prepared using a zero-based accounting method, meaning that they are
20 prepared with no reference to any prior year's budget. To accomplish this, CX&O starts
21 from zero and adds the expenses associated with the projects and department operation
22 planned to complete in the test year to arrive at the final projected test year spend. By
23 contrast, Exhibit A-53 (JRB-2), page 4, does not start from zero but instead starts from

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historical year actuals, and, as a result, must have the “Other Adjustment” variable applied to it so that the final projected test year spend is the same as what is shown in the CX&O budget. The figures in this column should *not* be disallowed as though they are unjustified expenses. They do not exist as a category of spending but merely reflect the difference in calculation methods between the CX&O budget and the hypothetical illustrations discussed above. Amounts included in the “Other Adjustment” column will be discussed throughout my testimony in the corresponding business area.

Q. Please provide a summary of the CX&O O&M expenses and capital investments projected in the test year.

A. CX&O is projecting capital expenses of \$13,000 in the bridge period 2025, \$680,000 in the bridge period 2026, and \$1.87 million in the test year, as mentioned above, as well as approximately \$35 million in O&M expense for the test year ending April 30, 2027. This amount comprises \$23.5 million of O&M expenses for Customer Interactions, and \$11.5 million for Billing and Payment. The CX&O O&M expenses are presented in detail on Exhibit A-53 (JRB-2). The historical and projected capital costs for these programs are included in Exhibit A-12 (JRB-1), Schedule B-5.3.

DEPARTMENT	CAPITAL	O&M
Customer Interactions	\$1.87 million	\$23.5 million
Billing & Payment	\$0.0	\$11.5 million
Total	\$1.87 million	\$34.9 million

The Company is also projecting \$4 million in test year capital, \$1.3 million in Rough Order of Magnitude (“ROM”) adjusted test year capital, and \$533,000 in O&M for customer investment to support the CX&O IT infrastructure. All IT-related costs discussed in this testimony are in the IT capital and O&M budget and discussed by Company witness Baker.

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1 **Q. Has the Company undertaken any initiatives to lower costs related to CX&O O&M**
2 **expense?**

3 A. Yes. Incorporated into the CX&O O&M projection is \$9 million of net recurring customer
4 benefit to the electric business due to changes to the payment process. This is the result of
5 implementation of a fee-based model for payments submitted through vendor payment
6 channels to ensure the cost distribution for payments is fairly represented between
7 residential customers and non-residential customers who choose to pay with a high-cost
8 payment method or fee-based channels versus those who use fee-free payment methods.

9 **Q. How is the remainder of your testimony organized?**

10 A. My testimony is organized as follows:

11 I. Customer Experience and Operations

12 A. Customer Interactions

13 i. Digital Customer Operations

14 a. IT—Customer Order Service Tracker

15 b. IT—Multi-Account Online Account Management

16 c. IT—Customer Product Family Enhancements

17 ii. Customer Contact Center

18 iii. Business Customer Care

19 iv. Credit and Assistance

20 v. Analytics and Outreach

21 B. Billing and Payment

22 II. Regression Analysis Results on Equity of Shutoffs

1 **I. CX&O**

2 **Q. Please describe CX&O.**

3 A. The CX&O organization strives to optimize a customer’s positive experience when
4 interacting with the Company. It has two major components--Customer Interactions and
5 Billing & Payment. Customer Interactions ensures that customers are equipped to connect
6 with the Company in their preferred channel (phone, Interactive Voice Response (“IVR”),
7 website, mobile app, or digital correspondence—such as text messages). Billing &
8 Payment provides customers with accurate, punctual energy bills and consistent payment
9 processes, and arranges personalized payment plans or settings (e.g. inability to pay
10 arrangements, pay by phone/website, payment alerts, choose your own bill due date) for
11 individual customers.

12 These two core functions are fundamental to accomplishing the Company’s
13 customer experience goals. The Company relies on its array of customer experience
14 offerings to ensure that customers are satisfied when interacting with Consumers Energy
15 and are therefore positively inclined to enroll in its available programs.

16 **Q. Is the Company’s IT witness sponsoring any Customer projects?**

17 A. Yes. Company witness Baker is sponsoring test-year funding for two Customer-related
18 technology projects (Customer Service Order Tracking (“COST”) and an expanded project
19 scope for the project Multi-Account Online Management Tool (previously titled
20 Commercial & Industrial (“C&I”) Online Management Tool)--both of which are discussed
21 in the Digital Customer Operation (“DCO”) section of my testimony) totaling \$1.6 million
22 in capital expenditures and \$345,879 in O&M expenses. Enhancements investment

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includes \$2.3 million in capital and \$186,838 in O&M costs. Please see Company witness Baker's testimony for additional information.

The IT department is a critical CX&O partner and CX&O relies on IT expertise to help develop and implement necessary digital solutions. IT maintains the Company's technology systems, ensuring they operate efficiently, reliably, and free from cybersecurity risks. IT also supports analytic platforms and solutions that provide deeper insight into customer needs, enabling CX&O to establish appropriate targets for metrics, products, and customer programs, which are necessary to allow CX&O to select the most cost-effective and beneficial solutions for customers. Together, these departments ensure customers receive secure, reliable, and positive experiences across all channels of interaction with the Company. Continued investment in technology requires additional ongoing funding to initiate, support, and maintain these platforms, as discussed in Company witness Baker's testimony. Test year capital and O&M for IT-related CX&O projects are noted below.

Project	Projected Test Year Capital	ROM Adjusted Test Year Capital	O&M
Customer Order Service Tracker	\$735,345	\$588,276	\$154,745
Multi-Account Online Account Management	\$893,008	\$714,406	\$185,073
Product Family Enhancements-Customer-Capital	\$2,365,309	\$0	\$0
Product Family Enhancements-Customer-O&M	\$0	\$0	\$186,838
Totals	\$3.9 million	\$1.3 million	\$532,717

A. Customer Interactions

Q. Please provide an overview of Customer Interactions.

A. Customer Interactions is responsible for the ownership and execution of the channels of customer interactions as identified above. This work includes the following areas of focus:

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the aforementioned DCO, Customer Contact Center, Business Customer Care (“BCC”), and Credit and Assistance. Each area of focus is aligned to the larger Customer goals of: (i) providing customers the opportunity to interact with Consumers Energy via their channel of choice; (ii) facilitating program enrollment and product selection to meet customer energy needs; (iii) providing support and guidance to the Company’s business customers; (iv) supporting the Company’s most vulnerable customers with information and enrollment in assistance programs; and (iv) achieving the Company’s clean energy goals. To effectively perform in these areas, the Company is projecting \$23.5 million of O&M expenses and \$1.87 million in capital for the test year ending April 30, 2027 as shown on Exhibit A-53 (JRB-2) and Exhibit A-12 (JRB-1), Schedule B-5.3.

i. Digital Customer Operations

Q. Please provide an overview of DCO.

A. DCO is responsible for the operation and continuous improvement of the Company’s customer-facing digital applications, including its website and mobile application. The team leads the design, development, and launch of the Company’s technologies, as well as ensuring that the technologies are responsive to customer needs and requested changes. Steady innovation is a testament to the group’s value to both the Company and the Customer.

The team collects customer survey feedback every month, which drives the team’s priorities in four simultaneous work cycles: (1) small, agile digital changes using available tools; (2) managing the design, development, and launch of monthly releases to add new features or modify user flows; (3) leading major technology projects that add new or modify existing functionality to better serve customers; and (4) executing the

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1 implementation of programs online to help accrue energy savings and clean energy
2 opportunities for customers.

3 The DCO manages a channel that gets more than 45 million customer interactions
4 annually and provides customers with a valuable self-service tool when managing their
5 energy consumption. The teams' services are particularly valuable when viewing 2024
6 statistics for the Company's website and mobile application, including 15.7 million views
7 related to checking billing status, 13.8 million related to payments via web or app, and
8 4.5 million views to view outage status. The DCO team keeps the website and mobile app
9 running, accessible for and responsive to Consumers Energy customers as a well-used
10 channel of choice. The DCO team is critical to the success of the company's objective to
11 digitize more transactions to better serve customers on the website, which is a more cost-
12 effective means of serving customers than other channels.

13 To continue this work, the Company is projecting approximately \$1.34 million of
14 O&M expenses for the test year ending April 30, 2027. As shown on Exhibit A-53
15 (JRB-2), this represents an increase in O&M expenses of \$431,000 from the \$907,000
16 expended in 2024. The primary driver of this is an increase in contractor-related costs in
17 the test year.

18 **Q. What types of transactions do customers complete online?**

19 A. The most common transactions customers complete using the Company's website and
20 mobile app are (1) checking the billing status of their account (15.7 million views in 2024),
21 (2) making payments (13.6 million views in 2024), (3) reporting outages or viewing the
22 status of an outage (4.5 million views in 2024), (4) checking energy usage information
23 (3.1 million views in 2024), and (5) investigating additional service information—such as

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1 auto-pay, eBill enrollment, budget billing, and information on products and services. The
2 Consumers Energy website also serves as the principal vehicle to enable customers to sign
3 up for clean energy program rebates, enroll in energy saving programs, and save money
4 with energy-efficient products. As discussed later in my testimony, the Company is also
5 capitalizing on the power of its digital tools to gather and share information that informs
6 Low- and Medium-Income customers about programs and services that can assist them in
7 meeting their special energy needs.

8 **Q. Please explain why the Company is continuing to invest in multiple digital methods**
9 **to allow customers to complete transactions or find information in their channel of**
10 **choice.**

11 A. The Company continues to invest in multiple digital methods for customer interaction for
12 several reasons. Continued investments are not only needed to keep pace with changes in
13 new and emerging technologies, but also customer needs, habits, and expectations. At the
14 same time those are changing, customer use continues trending toward more integrated and
15 sophisticated digital services. These investments also ensure channel parity so that
16 customers can complete all transactions in any or all channels. Additionally, expanding
17 the Company's digital channel lets customers complete a variety of activities on a
18 smartphone or computer at a time that may be more convenient than the limited call center
19 service hours, shifting costs to the more-cost-effective channel. In 2024, customers paid
20 \$4.7 million daily in bills through the web and mobile app. Both channels together are on
21 track to see \$1.7 billion in payments yearly. Online transactions cost approximately
22 \$0.11 versus \$10.18 per live agent call (utilizing internal contact center resources), making
23 this a cost-effective alternative to expanding the call center service hours.

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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 (e.g. DTE, UPPCO, Indiana Michigan Power/AEP) for which this has become the customer expectation, the Company continues to support several channels in response to customer needs and choices for communicating and completing transactions. The Company's IVR System currently co-exists in the digital platform space with the website/mobile website and the mobile app. Similarly, the Company maintains call centers and direct payment offices for customers who prefer to communicate or pay face-to-face. Many of these channels are maintained in service of the wide variety of customer needs given generational, locational, and socio-economic factors.

Q. Is the CX&O department proposing test year IT costs related to DCO projects?

A. Yes. Company witness Baker is sponsoring test year capital IT costs for two DCO projects: (i) \$735,345 in capital and \$157,505 in O&M costs in the test year for the Company's Customer Order Service Tracker; and (ii) \$893,008 in capital and \$188,374 in O&M for the Multi-Account Online Management Tool (formerly the C&I Online Management Tool). The customer benefit of each project is discussed below.

Additionally, Ms. Baker is sponsoring \$2.4 million in test year capital and \$186,838 in test year O&M costs for Customer IT Product Enhancements that include Mobile App and Web Chat AI.

a. Customer Order Service Tracker

Q. Please detail the COST.

A. The Company continues to seek support for its COST project (previous approval in Case Nos. U-21389 and U-21585). Helping the customer to understand where their request is

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1 in the process reduces frustration by providing a clear view into their order. This project
2 seeks to offer a simple, informative option which the customer can easily access and check.

3 The Service Tracker will provide both transparency to customers and oversight to
4 internal teams supporting utility service orders across Company service areas via:
5 (i) accurate and timely service order updates, tracking service order status and crew
6 location updates; and (ii) an interactive digital channel for use by dispatch, scheduling, and
7 field crews.

8 Crews will be able to provide both customers (via digital channels of choice) and
9 dispatchers real-time updates as they complete activities in customer areas and provide
10 accurate estimated times of arrival and work details. Customers will gain greater insight
11 into order status and access to updates that can yield improved customer experience.

12 **Q. What problem will COST solve for customers?**

13 A. Many incoming customer inquiries include “short cycle” orders, such as questions about
14 or reports of emergencies, forestry needs, or meter services issues. Customers have
15 previously had very limited visibility into when Company-assigned crews will be onsite
16 for this work due to a lack of relevant features within the Company’s digital channels that
17 can track and report accurate updates from dispatch, scheduling, and field crews. That lack
18 of awareness drives thousands of short cycle request-related calls into the call center. For
19 example, the Company completed 354,000 short-cycle request service orders in 2024,
20 many of which were initiated via the contact centers, and other various departments that
21 respond to customer requests.

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1 **Q. Does COST provide cost savings?**

2 A. Implementation of the COST is projected to yield significant cost savings through
3 enhanced customer communication and operational efficiency. By providing real-time
4 updates regarding field visits and scheduled work, COST aims to reduce the volume of
5 inbound customer inquiries regarding work status. This proactive information
6 dissemination addresses a critical customer need, mitigating the necessity for reactive calls
7 to the contact center and other departments that answer calls from customers (i.e., Dispatch,
8 Scheduling, and Field Operations).

9 The Company recognizes the inherent limitations of current communication
10 channels, particularly in accommodating customer schedule changes or the need for on-site
11 presence during service appointments. The absence of a digital self-service solution
12 necessitates customer reliance on telephone communication, incurring an average cost of
13 \$10.18 per call. These calls not only represent a substantial financial burden but also
14 constrain the contact center's capacity to deliver accurate and timely information to other
15 customers. The Company can address this inefficiency by providing this digital platform
16 that empowers customers to reschedule or cancel appointments, or to indicate their need
17 for on-site presence. Additionally, the tool provides added visibility for Company
18 dispatchers so that they may avoid assigning an additional or locationally challenging truck
19 roll because they had limited awareness of crew locations and routes. Each truck roll comes
20 with a cost of approximately \$450.

21 **Q. Why is this project important in the Customer space?**

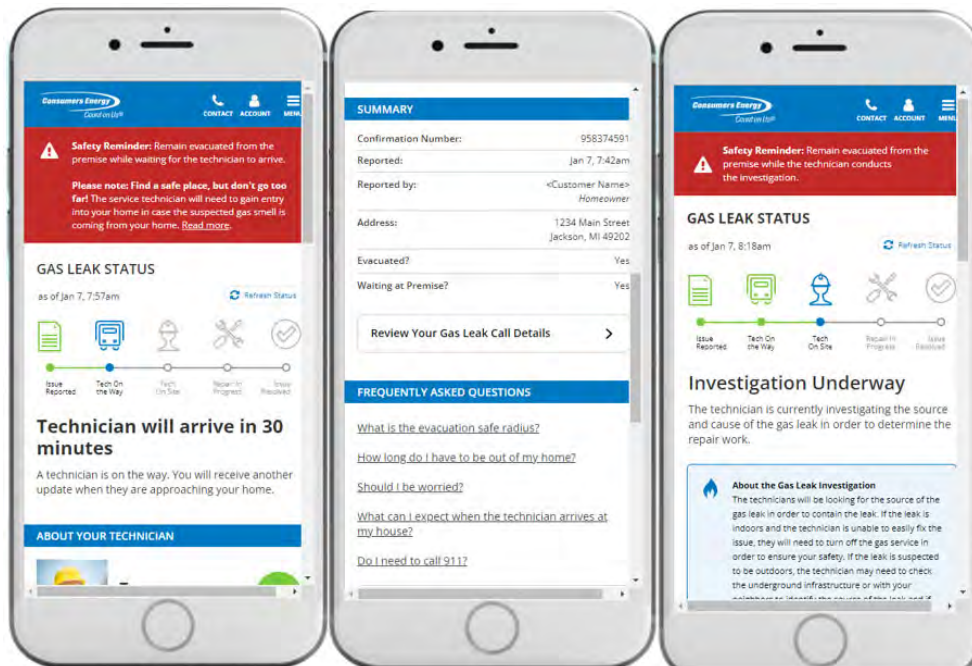
22 A. Once fully implemented, COST will provide the following benefits:

- 23 • Reduced Call Volume: By enabling self-service options, COST will directly
24 decrease the number of inbound calls related to scheduling and status inquiries.

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- Improved Customer Experience: Real-time updates and flexible scheduling options will enhance customer satisfaction by providing greater control and transparency for both customers and dispatchers and reduce the waste of repetitive crew dispatching.
- Increased Operational Efficiency: Reduced call volume will free contact center resources, allowing agents to focus on more complex customer issues and improve overall response times.
- Cost Savings: The reduction in call volume will translate to substantial cost savings, including all the departments that answer the call to serve customers.
- Data Accuracy: By providing a digital platform to document customer change order requests, the Company will have more complete and accurate information with which to plan its call center and dispatched resources.

The images below are mock-ups of the potential user experience flow, designed around a mobile device user in a gas leak emergency.



Q. How will the Company implement COST?

A. The Company will facilitate the deployment and implementation of COST using a multi-phased approach after documenting testing with customers' concepts and validating the application's processes. The multi-phased approach would use design thinking

principles of (1) Project Scoping and Team Formation, (2) Research, (3) Definition and Ideation, (4) Prototype and test MVP (Minimum Viable Project), and (5) Implementation MVP and Scale.

Q. Please provide a detailed breakdown of all costs involved with this project and how the requested money will be spent.

A. A detailed breakdown of costs for historical, bridge, or test years may be found in Company witness Baker's testimony.

b. Multi-Account Online Management Tool

Q. Please provide a brief overview of the Multi-Account Online Management Tool.

A. Currently, customers with multiple accounts must manage a separate login for each account in the self-service customer portal for account management and must utilize a third-party portal to complete collective billing activities. This system is outdated, labor intensive, prone to human error, and generative of the waste and emissions associated with the production, transport, and administration of paper bills. Peer utilities like DTE and others have long implemented multi-account online account management functionality, recognizing that all business and residential customers can directly benefit.

Q. Please provide a brief description of one log in and other benefits.

A. Development of this tool directly addresses customer feedback that this specific issue is burdening their ability to manage and pay their utility bills, which is the most important transaction a customer has with the Company. When this is not functional, not only does the Company lose the efficiency, accuracy, and security of online account management and billing, but also the opportunity to opt-in, learn more, or otherwise engage with Consumers Energy's EWR and other retail offerings central to the Company and Michigan's clean energy strategies.

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1 **Q. Has this project been included in a previous rate case?**

2 A. Yes. The Company originally requested funding for this project in Case No. 21585 under
3 the project title C&I Online Management Tool.

4 **Q. Why was the name of the project changed?**

5 A. Both the name of the project and the scope of the project were changed to reflect the reality
6 that a multi-account tool is beneficial for a larger population of customers than just business
7 customers.

8 **Q. Please explain.**

9 A. While assessing the feasibility of developing a tool for the Company's C&I users with
10 multiple accounts, it became clear that there was also a large population of residential
11 customers who also had multiple accounts for reasons noted below. Developers
12 recommended that this population be included to make the investment more impactful and
13 relevant to more customers.

14 **Q. How many additional customers would the multi-account tool reach?**

15 A. The initial C&I tool was scoped to reach the Company's approximately 39,500 business
16 customers with multiple accounts. The broader-scoped multi-account project will also
17 reach approximately 115,000 residential customers who have:

- 18 ▪ More than one property;
- 19 ▪ More than one meter/account (Outbuildings etc.);
- 20 ▪ Multiple accounts due to moving and/or new building; and
- 21 ▪ Non-energy billing accounts

22 The multi-account project will also reach approximately 50, 000 cross-over, or hybrid,
23 customers who have a mix of residential and C&I accounts.

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1 **Q. Please describe the problem this project will solve for business customers.**

2 A. Consumers Energy's multi-account customers include Michigan's largest corporations;
3 Federal, state and local municipalities; healthcare; universities; franchises; agriculture; and
4 housing. From water to streetlights, healthcare, and government services, virtually every
5 Michigander is served by power delivered through meters managed by a single customer
6 with multiple accounts. As noted above, these customers currently lack the basic
7 multi-account management features that are offered by most other companies, including
8 DTE. This increases administrative burden and opens opportunities for human error.

9 For most of these customers, this pain point presents a daily struggle that requires
10 significant effort, leading many customers to opt out entirely from online tools and
11 communications. These customers instead prefer to keep paper files and binders organized
12 with the paper trails of hundreds of accounts. Many multi-account customers need several
13 individuals across their businesses to have easy access to their utility accounts, but this
14 currently requires tracking and utilizing multiple logins to the Company's self-service
15 portal and payment of several individual bills.

16 **Q. Please describe the problem this project will solve for residential customers with**
17 **multiple accounts.**

18 A. Any customer who is moving, has more than one property, or has a Consumers Energy
19 non-energy billing account for new builds and upgrades will benefit from the ability to
20 manage these accounts online with one login.

21 Managers of multi-dwelling residential buildings ("MDUs") have noted hardships
22 related to the many accounts they manage without a functional online interface. With
23 consistently changing occupancy, landlords and apartment owners who largely serve

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1 middle and low-income customers are frequently exposed to this pain point and require
2 accounting staff dedicating significant work time managing hundreds of individual
3 payment accounts, with one mid-sized MDU business citing as many as 40 hours a month
4 to manage their utility bills.

5 **Q. What is the cost of the project (tangible and intangible)?**

6 A. The Multi-User Online Account Management project requires \$893,008 in capital
7 expenditures and \$188,374 in O&M expenses in the test year. The project will enable
8 additional features supporting customers' ability to manage their accounts online.

9 **Q. Please detail what additional features will include.**

10 A. With the additional features, all multi-account customers will be able to combine multiple
11 accounts under a single login and assign authorizations internally to their own various
12 location managers.

13 **Q. Do the estimated costs include any savings for CX& O (direct/indirect)?**

14 A.

- 15 • BillTrust third party system
- 16 • Paper bills and postage
- 17 • Landlord Portal
- 18 • Call Center time

19 **Q. Did the Company consider other potential solutions?**

20 A. Yes. The Company considered, but ultimately excluded, the following options:

- 21 • BillTrust – a payment only add-on solution that allows a customer with multiple
22 accounts to submit a single payment. This does not allow for account
23 management and still requires individual logins for account access. BillTrust
24 has also been responsible for causing errors in payment reporting resulting in
25 unwarranted shut off notices to some customers.

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BillTrust features are limited to the payment transaction only, and do not allow account management.

The existing process and implementation require extensive support from customer service representatives and other internal resources to support collective billing. In addition to the yearly fee for utilizing the platform, the Company continues to assign personnel to manage, support, and correct issues resulting from this product.

- Paper Management – Due to the lack of digital multi-account management, many of these customers prefer to file, store, and mail paper bills. To manage this analog undertaking, customers have reluctantly gone back to hard copy means to label, file, store, and mail paper bills. Potential ideas to improve the experience of organizing hundreds of individual bills include branded binders, hard copy filing solutions, postage, and a dedicated customer service line.
- Do nothing – Online and digital account management is one of the first and most consistent interactions Consumers Energy has with its customers. When this is not functional, we not only lose the efficiency, accuracy, and security of online account management, but also the opportunity to opt-in, learn more, or otherwise engage with the Company's EWR and other retail offerings.

c. Customer Product Family Enhancements¹

Q. Please describe how Customer Product Family Enhancements are identified and implemented.

A. CX&O Customer Product Family Enhancements are technology improvements which benefit customers and are implemented in response to the launch of a channel, customer tool, project completion, and/or direct customer feedback. Depending on the need identified, enhancement dollars could be utilized to support the enhancement of any customer supporting feature and/or capability, often as emerging requests. These items are small-scope items with a reduced budget and fewer resource requirements in comparison to larger capital investments. Having the flexibility to implement Customer Product Family Enhancements enables the Company to meet the customers emerging needs.

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.

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Examples of enhancements include improving overall functionality of the channel or tool, analytics on platform usage, addressing issues identified internally or via customer feedback, adding relevant or customer-driven capability, and performance monitoring.

Q. How do Customer Product Family Enhancements benefit the Company's customers?

A. Enhancements assist the Company in providing a better, more optimized customer experience for customers through improved understanding of how they use the channels or tools, which features are important to their experience, and how the channels or tools are performing.

Q. What Customer-related Enhancements are included in this case?

A. Enhancements for the Company's Mobile App, Web Rebate Information for Personalization, and Web Chat AI are included.

Q. Please discuss the benefits of these Enhancements.

A. The benefit of software enhancements in the Customer Portfolio 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.

Q. Why is it important to continue to fund Enhancements for Mobile App, Web Rebate Information for Personalization, and Web Chat AI?

A. In providing different channels of communications, it becomes a necessary obligation for the Company to update and maintain the tools customers prefer to use. Enhancements can range from a wholesale update to customer-requested functionality and can include updates, fixes, and changes in the applications. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain

business agility. Investment into these enhancements ensure these tools work as requested or expected. The three digital tools are currently in existence and in use by customers and consequently require updating and maintenance.

Q. Please provide a detailed breakdown of all costs involved with this project and how the requested money will be spent.

A. A detailed breakdown of costs for IT historical, bridge, and test years may be found in Company witness Baker's testimony.

ii. 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 2024, call center representatives answered over 2.6 million customer calls. Likewise, the IVR system addressed 4.7 million calls in 2024.

To continue this work, the Company is projecting \$14.6 million of O&M expenses for the test year ending April 30, 2027. As shown on Exhibit A-53 (JRB-2), this represents an increase in O&M expenses of \$700,000 from the \$13.9 million expended in 2024. Labor, including contract step and merit increases, accounts for the majority of the increase.

iii. Business Customer Care

Q. Please provide an overview of BCC.

A. BCC directly impacts the Company's C&I customers, and includes the Business Center, which assists the Company's larger business customers with support such as phone agents and account management. BCC's main goal is to deliver exceptional customer experience,

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1 while identifying opportunities that provide the Customer with added energy value and
2 opportunities. Overall, BCC serves approximately 100,000 customers, equating to
3 200,000 contract accounts.

4 To continue the work in this area, the Company is projecting \$1.8 million in O&M
5 expenses for the test year ending April 30, 2027. As shown on Exhibit A-53 (JRB-2), this
6 represents an increase in O&M expenses of \$238,000 from the \$1.6 million expended in
7 2024, with the increase attributed to higher labor and contactor costs in this area.

8 **iv. Credit and Assistance**

9 **Q. Please provide an overview of Credit and Assistance.**

10 A. Credit and Assistance consists of: (1) Theft Investigations; (2) Revenue Operations; and
11 (3) Energy Assistance, which collectively manage the Company's collections cycle and
12 support its most vulnerable customers by connecting them with Company-sponsored
13 payment plans and public assistance funding to help customers pay their bills.

14 **Q. Please provide additional information about the responsibilities of the Theft**
15 **Investigation Team.**

16 A. Under the credit umbrella, the Theft Investigation Team provides the critical service of
17 identifying and ending energy theft in the Company's service territory - important both for
18 maintaining the safety and integrity of the Company's system and minimizing all
19 customers' costs. In 2024, the team identified 2,182 confirmed cases of theft and billed for
20 \$1,584,651.03 in unauthorized use and investigation costs – a decrease of 615 cases but an
21 increase of about \$439,000 billed over the previous year.

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1 **Q. Please provide additional information about the responsibilities of the Revenue**
2 **Operations Team.**

3 A. Also under the credit umbrella, Revenue Operations addresses past due customer accounts
4 or those involved in bankruptcy. Employees within this area manage the collections cycle,
5 from issuing a notice to customers through visiting a customer's premises to disconnect
6 service. This group also manages contracts with outside collection agencies to recover
7 payments from customers with outstanding balances. In 2024, the Company contracted
8 with outside collection agencies for \$1.6 million (covering recovery for both gas and
9 electric accounts). Consequently, the agencies recovered \$9.4 million from previously
10 written-off customer balances, of which \$3 million accounted for gas-only recoveries
11 (32% of total). Recovery of these payments directly offsets the uncollectible expense
12 discussed in the testimony of Company witness Matthew J. Foster.

13 **Q. Please provide information about the responsibilities of the Energy Assistance Team.**

14 A. The Energy Assistance Team is responsible for administering the Company's various
15 assistance plans, including the Consumers Affordable Resource for Energy ("CARE")
16 Program, which supports low-income customers who may be struggling to pay their
17 monthly energy bills and helps to provide customers with either a one-time bill assistance
18 payment or on-going support via enrollment in an Affordable Payment Plan ("APP"). The
19 Company's administration of assistance plans allows it to offer customers reduced monthly
20 bills and gradually pay down any arrears brought into the program. By coordinating with
21 other organizations in fiscal year 2024, this team obtained \$8.8 million of APP-specific
22 assistance and an additional \$7.2 million in one-time assistance for its customers requested
23 through the Michigan Energy Assistance Program ("MEAP"). Additionally, Consumers

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1 Energy customers received \$38.4 million in State Emergency Relief payments and
2 \$12.7 million in Home Heating Credit assistance. Note that these figures include assistance
3 for both electric and gas customers.

4 To continue the work in this area, the Company is projecting \$2.8 million in O&M
5 expenses and \$1.87 million in capital for the test year ending April 30, 2027. As shown
6 on Exhibit A-53 (JRB-2), the O&M request represents an increase of \$450,000 in O&M
7 expenses from the \$2.4 million expended in 2024, due to increased labor and contractor
8 (agency) costs, as well as a decrease in energy theft credits.

9 **Q. Is the Company requesting additional funding support in the Credit and Assistance**
10 **area?**

11 A. Yes. The Company is requesting \$1.87 million in capital costs to support the Low
12 Moderate Income (“LMI”) Customer Support Enhancement project. Additionally, the
13 Energy Assistance team is proposing an increase, from \$30/meter to \$42/meter, in the way
14 it funds and administers the Low-Income Assistance Credit (“LIA” credit) in response to
15 Michigan Public Acts 168, 169, 170, and 198, which were approved by lawmakers in late
16 2024, as well as a tariff change to increase eligibility for the Shut Off Protection Plan
17 (“SPP”).

18 **Q. Please describe the LMI Customer Support Enhancement project.**

19 A. The LMI Customer Support Enhancement project is designed to support LMI customers in
20 reducing their utility bill expenses by driving greater awareness and enrollment into
21 eligible programs and services. This helps customers alleviate energy burden, reduces the
22 risk of service disconnections due to unpaid bills, and can ultimately improve household
23 stability.

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1 The project focuses on four core functions: (1) Simplified Program Enrollment--
2 centralizing and simplifying the enrollment process for multiple programs to eliminate
3 confusion and build trust; (2) Proactive Communication and Program Awareness—with an
4 aim to engage customers ahead of crises based on behavioral indicators, ensuring they are
5 aware of and enrolled in assistance programs that can help them manage their energy costs
6 effectively; (3) New & Improved LMI Offerings—with a focus on integrating existing
7 programs and redesigning them to better serve LMI customers; and (4) Continuous
8 Improvement-- ensuring that strategies are refined based on customer feedback to remain
9 effective and responsive to customer needs.

10 **Q. Please detail the goals of the project.**

11 A. The primary goals of the project are to proactively communicate with LMI customers
12 before they reach a crisis point, deliver personalized experiences that anticipate each
13 customer's needs and preferences, and simplify the enrollment process for assistance
14 programs. Currently, only one in six LMI customers engage in Consumers Energy
15 Assistance programs, with most of these interactions driven by immediate crises. The
16 project aims to increase service from engaging 1 in 6 LMI customers to serving 1 in 3 LMI
17 customers, significantly expanding support to those in need.

18 The project's mission is to better serve LMI customers by providing easy access to
19 meaningful assistance, achieved via the four core functions detailed above. By addressing
20 identified barriers to early LMI interaction and enrollment in utility programs, the project
21 can provide solutions that make interactions more accessible, supportive, and efficient,
22 ultimately enhancing the overall customer experience and financial stability for LMI
23 customers.

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1 By tailoring communication based on behavioral indicators, the project seeks to
2 increase the likelihood of preventing a crisis through early engagement. Additionally, the
3 project aims to facilitate enrollment into utility programs such as energy assistance,
4 payment plans and arrangements, EWR, DR, renewable energy programs, and more to
5 avoid shut-off crises and reduce the energy burden for LMI customers. Continuous
6 improvement is also a key goal, with strategies being refined based on customer feedback
7 to ensure the project remains effective and responsive to customer needs.

8 **Q. How will this be achieved?**

9 A. This will be achieved through a series of strategic steps aligned with the four core
10 functions. *Simplified Program Enrollment* will involve implementing a streamlined,
11 self-identification workflow that allows customers to find and enroll in all relevant
12 assistance programs. *Proactive Communication and Program Awareness* will be built to
13 identify and reach out to customers showing early signs of crisis, educating them about
14 assistance options and directing them to the streamlined, digital workflow. *New &*
15 *Improved LMI Offerings* will integrate existing offerings such as payment plans, EWR,
16 DR, renewable energy programs, and more to provide a comprehensive support system for
17 LMI customers. *Continuous Improvement* will be ensured by continuously gathering
18 feedback from customers and stakeholders to refine the user flow and outreach strategies,
19 making the project adaptable and responsive to emerging challenges and customer needs.

20 **Q. Why is it important for the Company to receive approval for this project?**

21 A. This project directly improves customer experience by supporting a significant portion of
22 the Company's customer base. LMI customers account for more than 1 of every 3
23 customers in Consumers Energy's service territory; 11% are low income, meaning they are

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1 in crisis and unable to pay their energy bill; 26% are moderate income, commonly
2 identified as being one crisis away from being able to pay their energy bill. Currently, only
3 1 in 6 LMI customers engage in Energy Assistance programs with the majority of these
4 interactions driven by immediate crises that limit ability to introduce solutions and
5 programs given the urgent customer need. Further, interactions at near crisis and crisis
6 moments impacts trust, often resulting in customers being less receptive and open to
7 solutions the Company can offer or provide access to.

8 Moreover, approval of this project delivers on the priorities of the MPSC's Energy
9 Affordability and Accessibility Collaborative ("EAAC") and Low-Income Energy Policy
10 Board that highlight the importance of streamlining energy assistance and program
11 enrollment processes to support increased awareness, participation, and customer benefit.
12 This need for attention to simplified and effective processes is also highlighted in Public
13 Act 229 of 2023, which instructs utility EWR programs to minimize barriers to
14 participation in low-income energy waste reduction programs and reduce overly
15 burdensome verification processes. Overall, this work will provide proactive, immediate
16 information and relief, helping customers manage costs, avoid disconnection, and maintain
17 essential services, all of which will enhance customer well-being with tangible, positive
18 outcomes.

1 **Q. Since the LMI project's implementation in December 2024, has there been success in**
2 **improving access to assistance?**

3 A. Yes. The project has been operational since December 2024. In that short time, the project
4 has clearly demonstrated its value in improving access to assistance for all Consumers
5 Energy customers.

6 The project is already yielding strong results, with a measurable increase in
7 customer engagement and uptake—indicators that the tool is well-designed to meet the
8 needs of the population it is intended to serve. Since its launch, over 55,000 customers
9 have interacted with the tool, and 12,000 customers have enrolled in an offering, with 22%
10 of interested customers enrolling in programs (compared to .05% of customers who enroll
11 after being reached via email), ensuring that the efforts put into developing and promoting
12 the tool are yielding tangible benefits. Given its strong foundation, evidence-based design,
13 immediate positive outcomes, and clear trajectory for ongoing improvement, this LMI
14 project is a reasonable and prudent investment. Funding it ensures that the Company can
15 continue delivering meaningful support to customers who need it most.

16 **Q. Can the Company provide results that demonstrate effectiveness and progress toward**
17 **the stated goals of the LMI project?**

18 A. Yes. Since its launch, the LMI project has delivered several measurable outcomes that
19 demonstrate its early effectiveness and validate the Company's approach. Within the first
20 four months of deployment:

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- Over 55,000 customers engaged with the tool since launch, and nearly 30,000 (55%) of those users have self-identified as LMI, indicating high visibility within and interest from the intended user base.
 - Of the 55,000 customers who interacted with the tool roughly 40% completed the full eligibility assessment, successfully identifying one or more programs for which they may qualify.
 - Of the 12,000 users completing the flow, nearly 20% enrolled in more than one offering, demonstrating the effectiveness of the simplified digital enrollment flow in making it easier for customers to access the programs they need.
 - o By streamlining the process, customers can quickly and efficiently determine their eligibility and enroll in multiple beneficial programs, leading to better support and improved outcomes for those in need.
 - On April 20, 2025, Green Giving was added to the simplified digital enrollment experience. In just the first hour, six customers enrolled—matching the total enrollments agencies achieved in the previous six weeks.
 - o Since then, the Company has enrolled 515 low-income customers digitally, while agencies have enrolled 10.
- This contrast highlights the urgent need to streamline enrollment and eliminate administrative barriers. Modernizing the Company’s approach is essential to better serve its customers and maximize program impact.
- 87% of users that completed the survey reported that it was extremely easy², or easy to complete the experience.
 - 56% of users that completed the survey reported that they felt the offerings provided to them were extremely personalized or very personalized to them.
 - By implementing the tool, the Company has reduced the need to send approximately 300,000 emails to promote individual products to reach enrollment goals, streamlining the Company’s outreach efforts and maximizing efficiency.

² Based on a rating scale the rating scale includes:
Extremely Easy
Very Easy
Moderately Easy
Slightly Easy
Not Easy at all

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- The tool has captured over 3,000 leads for EWR programs.³ The tool’s ability to capture leads organically indicates a user-friendly and effective design, making it easier for customers to navigate and enroll in programs.

These results affirm that the tool is immediately delivering on its intended purpose: reducing enrollment barriers, increasing program visibility, and helping LMI customers more easily access the support they need. Continued monitoring and feedback collection will allow the Company to further refine the tool and expand its impact in the months ahead.

Q. Was customer research used to develop this project?

A. Yes. The Company initiated primary and secondary research to better understand LMI customers and to identify barriers to awareness about assistance options and participation in utility programs. The Company used existing research from a variety of partners (Uplight and Accenture), which established a clear need for the LMI Project, and then undertook primary research to validate and refine the learnings. The primary research included more than 2,000 LMI customers, 95% of whom live in Michigan. Through surveys, interviews, and ethnographic studies (please see additional research details below), these customers shared insights on their experiences, challenges, and expectations, ensuring the project is informed by the voices and needs of those it aims to serve.

Q. Please discuss the details of the customer research that was conducted.

A. Research included:

- *Solution Concept / Usability Testing:*
 - o 6 usability tests with 104 participants for the MVP “My Personalized Offerings”, 54% (56) were Michigan residents

³ The tool captures leads to send to CLEAR, to then contact customers to schedule Home Energy Analysis appointments.

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- o 6 Solution concept tests (partnered with Uplight for 1 of the 6 tests)
- o 1 usability test for account dashboard redesign
- o Continuing in 2025 with solution enhancements and program development
- *Customer Panel (Survey):*
 - o Self-Identification Validation survey with 1,967 Consumers Energy customers
 - o Account dashboard redesign concept preference survey, 60 LMI participants
 - o Continuing in 2025 with message testing
- *In-Depth Interviews:*
 - o Generate broad LMI insights
 - o Validate direction for My Personalized Offerings
 - o Inform outreach channels and messaging (working with Uplight)
- *Card Sort / Tree Test:*
 - o Determine information architecture for account dashboard website, 223 participants
- *Diary Study:*
 - o Generate broad LMI insights, 13 LMI customers (non-Company) over the course of 10 days
- *Desk Research sources:*
 - o Accenture, eSource, Civilla, Chartwell

The Consumers Energy Experience Design and Research teams led efforts to generate new insights, validate existing findings, and test solutions with its customers and the LMI population. In some instances, the Company independently ran the study, in others the Company worked alongside partners (Uplight and Accenture). The Company also

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utilized an archive of published work from various partners for desk research. The insights and data collected were utilized to identify core areas of focus.

Q. Please discuss the results of the customer research.

A. Research findings revealed that 18% of LMI customers were unaware of how to access help, 36% were unaware they qualify for programs, 25% perceived the process as overly complex and time-consuming, 51% felt too overwhelmed to take on another project, 21% considered EWR programs to be price-prohibitive, and 46% were unfamiliar with utility assistance for low-income families. Additionally, research from a 2024 Los Angeles Dept. of Water and Power case study showed that using income self-attestation increased program enrollment and willingness to initiate assistance requests by 40%. Customer research was foundational in the development of this project to ensure outputs are not only accessible and effective but also directly address the needs and preferences of LMI customers, ultimately making it a valuable tool for reducing utility bills and supporting financial stability.

Q. How will investment in this project benefit customers?

A. While this project's primary focus is to support LMI households, its results will benefit all Consumers Energy customers with five key deliverables: (1) Enhancing energy equity by broadening access to bill assistance and utility programming; (2) Addressing the risk of unpaid bills and service disconnections--preventing service cuts reduces administrative costs and lost revenue, which will positively impact all customer; (3) Continuing to build trust with LMI customers, fostering a sense of loyalty and increasing a customer's willingness to engage proactively, not just in times of crisis; (4) Reducing the bill and energy burden on low-income families, enhancing their overall quality of life and financial

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1 stability; and finally (5) Engaging LMI households in both bill assistance and clean energy
2 solutions, which is crucial for environmental sustainability.

3 While the Company is currently focused on evaluating the potential to redesign or
4 develop new offerings to better serve LMI customers, the scope of the LMI Customer
5 Support Enhancement Project includes exploring ways to support customers who do not
6 currently qualify for low-income assistance but could still face significant financial
7 challenges.

8 **Q. Please provide a detailed breakdown of all costs involved with this project for the test**
9 **year and how the requested funds will be spent.**

10 **A.** Please see a cost breakdown by Core Function in the chart below:

Core Functions	Cost
Simplified Program Enrollment	\$600,000
Proactive Communication and Program Awareness	\$370,000
New & Improved LMI Offerings	\$700,000
Continuous Improvement	\$200,000
Total	\$1.87M

11 **Q. How was the project implemented?**

12 **A.** The project was implemented following the four core functions and the funding requested
13 in this case will be also be accounted for using these functions, as detailed below:

14 **1. Simplified Enrollment**

- 15 • **Streamlined Access:** Developing and implementing a streamlined user
16 flow to simplify the process for customers to find and enroll in relevant
17 programs, ensuring easy access to support without unnecessary hurdles.

18 **2. Proactive Communication and Program Awareness**

- 19 • **Proactive Outreach:** Building the capability to identify and reach out to
20 customers showing early signs of crisis by using data analytics to detect
21 at-risk customers and initiating contact to educate them about available
22 assistance options.

- **Enhanced Awareness:** Educational initiatives funded by this allocation will increase awareness about the Company’s programs through targeted communication campaigns and partnerships with community organizations.
- **Personalized Communication:** Funding will support the development of a notification preference center, ensuring customers receive information through their preferred communication channels, improving engagement and satisfaction.

3. New and Improved LMI Offerings:

- **Comprehensive Support System:** Integrating existing offerings such as payment plans, EWR, demand response, and renewable energy programs to create a comprehensive support system for LMI customers.
- **Redesigned Programs:** Funding will support the redesign of current offerings to better serve LMI customers, making them more accessible and effective. This includes simplifying eligibility requirements, enhancing program capacity and scalability, and ensuring that the programs deliver meaningful value.
- **New Offerings:** Development of new moderate and low-income customer offerings will address specific needs and gaps in current support, providing greater value and reducing barriers to participation.

4. Continuous Improvement and Feedback

- **Responsive Adjustments:** Continuously gathering feedback from customers and stakeholders to refine the user flow and outreach strategies, ensuring that the project remains adaptable to customer needs and responsive to emerging challenges.
- **Data-Driven Enhancements:** Advanced reporting and modeling tools funded by this allocation will provide insights into program performance, enabling data-driven decisions and optimizations.
- **Customer Satisfaction:** Regularly collecting and analyzing feedback will help identify and address any barriers to program participation, leading to higher customer satisfaction and trust.

By implementing these core functions, the project aims to provide a more efficient, accessible, and valuable experience for LMI customers, ultimately enhancing their overall experience and financial stability.

1 **Q. Please describe each assistance program the Company would target for enrollment**
2 **under this enhancement.**

3 A. In launching the project, the Company aims to integrate existing programs within its energy
4 assistance, payment plan, EWR, DR, and renewable energy portfolios into a streamlined
5 system. This integration will create a comprehensive support network, enabling customers
6 to easily identify and access the best options to reduce their energy burden without
7 extensive searching.

8 The Company is currently evaluating its programs under the new and improved
9 LMI offering function to determine which programs to add and when, as well as evaluating
10 if current offerings can be redesigned to better serve LMI customers by making them more
11 accessible and user-friendly. This includes simplifying program requirements, enhancing
12 scalability, and ensuring that the programs deliver meaningful value.

13 The initial launch of the Simplified Enrollment flow includes five key programs
14 designed to support the Company's LMI customers. These programs are:

15 **Home Energy Analysis & Helping Neighbors Program (income qualified):**

- 16
 - Provides an evaluation of how the whole home uses energy and includes the
- 17
 - installation of free product upgrades to improve energy efficiency.

18 **Budget Plan:**

- 19
 - Offers a consistent monthly payment plan with quarterly reviews to help
- 20
 - customers manage their energy costs predictably.

21 **Customer Selected Due Date:**

- 22
 - Allows customers to select the date on which their monthly bill is due,
- 23
 - providing flexibility to align bill payments with their financial schedules.

24 **Billing & Payment Alerts:**

- 25
 - Sends text or email alerts to remind customers of bills and payments due,
- 26
 - helping them stay on top of their financial obligations.

Link to MI Bridges and 2-1-1 (income qualified):

- Provides a link to the Michigan Assistance webpage and a click-to-call option to 2-1-1, connecting customers with additional support resources.

This diverse mix of programs aims to assist customers with billing and usage management, ensuring they have access to the support they need to manage their energy costs effectively.

Through the project, the Company will evaluate and determine if there is a need to expand its programs through ongoing analysis and iterative design. This commitment ensures that offerings remain relevant, effective, and responsive to the evolving needs of customers. The Simplified Enrollment Flow is designed to be inclusive and adaptable, allowing for the integration of the most supportive and beneficial programs for LMI customers. By continually refining and adding to the portfolio, the Company aims to create a dynamic and comprehensive support system that addresses the unique challenges faced by LMI customers, providing them with the resources they need to manage their energy costs effectively and improve their overall financial stability.

Q. What other changes is the Company proposing that will assist customers in managing their energy costs?

A. The Company is also proposing an increase in the LIA credit, from \$30 to \$42 per meter for 2026, with an annual scaled increase through 2029. The Company is also requesting the number of customers receiving the credit in 2026 be increased to 6,200, with increases of 1,000 per year through 2029.

Q. Why is the Company proposing these changes?

A. An estimated 26% of Consumers Energy customers are payment challenged and living within the moderate-income level. As inflation and economic factors have challenged

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sustainability for many households, the moderate-income customer segment has limited access to assistance options.

These changes would also facilitate the Company's alignment with Michigan Public Acts 168, 169, 170, and 198, which were approved by lawmakers in late 2024 to improve and modernize MEAP by expanding program eligibility, increasing available funding, and ensuring equitable access to funding. Please see the chart below for a detailed explanation of the funding increase.

Customer Count	LIA Credit Per Month	Number of Months	Annual Cost	Cost Difference from Previous Year
4200	30	12	\$ 1,512,000.00	\$ -
5200	40	12	\$ 2,496,000.00	\$ 984,000.00
6200	45	12	\$ 3,348,000.00	\$ 852,000.00
7200	50	12	\$ 4,320,000.00	\$ 972,000.00
8200	55	12	\$ 5,412,000.00	\$ 1,092,000.00

Q. Who is eligible for the LIA credits?

A. Customers currently eligible for LIA credits include:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months;
2. Customers who have received assistance from a MEAP;
3. Customers who have received a Home Heating Credit energy draft;
4. Customers in the State Emergency Relief program;
5. Customers who receive Medicaid; and
6. Customers that have participated in a Supplementary Nutrition Assistance Program ("SNAP") where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

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1 **Q. How are LIA credits currently applied?**

2 A. LIA credits are currently applied to the energy accounts of customers who are enrolled in
3 CARE⁴. The LIA credit helps to offset the agency assistance credit portion that provides
4 balance forgiveness as customer complete on time payments, allowing agencies to serve
5 more customers.

6 **Q. How many customers does the Company currently provide with the LIA credit?**

7 A. The Company currently provides 4,200 customers with the credit.

8 **Q. How many customers/credits will fall into the test year?**

9 A. The Company proposes that 5,200 credits be available during the test year.

10 **Q. What would be the total costs for increased recipients at an increased cost over the**
11 **test year?**

12 A. The total costs for the test year would be \$ 2,788,632 Calculated from:

13 (5,533 customers @\$42 each) * 12Months

14 **Q. Is the Company proposing any other changes in the Credit and Assistance area?**

15 A. Yes. The Company is also proposing changes to eligibility for the SPP and resulting tariff
16 language changes. To better serve the needs of moderate-income customers with more
17 affordable payment options, the Company is proposing to increase the SPP enrollment
18 Federal Poverty Guidelines eligibility cap to offer more options to roughly 700K moderate
19 income customers.

⁴ The Company's CARE program is designed to assist income-qualified customers in managing their energy use and bills more effectively. CARE provides customers with bill assistance via a 24-month program that includes a fixed monthly bill—offering a consistent, reduced monthly payment plan that makes budgeting for energy expenses more manageable. As customers make regular, on-time payments, existing past due balances will be forgiven. Customers may also be provided with no-cost, in-home energy efficiency upgrades to help reduce energy costs.

1 **Q. What is the current SPP?**

2 A. The current SPP is available for eligible customers who are at or under 200% of the Federal
3 Poverty level. As the moderate income or Asset Limited, Income Constrained, Employed
4 (“ALICE”) customers struggle to find affordable ways to manage their utility bills,
5 increasing the eligibility to 400% or less of the Federal Poverty level will offer another
6 resource for customers to manage their utility bills.

7 **Q. Why is the Company proposing changes?**

8 A. An estimated 26% of Consumers Energy customers are payment challenged and living
9 within the moderate-income level. As inflation and economic factors have challenged
10 sustainability for many households, the moderate-income customer segment has limited
11 access to assistance options. This change in eligibility guidelines would increase eligibility
12 for any customer that self attests that annual income is at or below 400% of federal poverty
13 level guidelines. This change would increase program eligibility to 26% more customers.

14 **Q. Please detail any tariff language changes that would result from the increase.**

15 A. Please reference Company witness Brittani Gray’s Exhibit A-16 (BAG-2), Schedule F-5
16 for proposed changes in related tariff language.

17 **iv. Analytics and Outreach**

18 **Q. Please describe Analytics and Outreach.**

19 A. The Analytics and Outreach group serves a vital function for incorporating customer
20 feedback and data into the Company’s operations, which directly contributes to improving
21 customer experience. This allows the company to use its resources more efficiently, target
22 communications to precise customer segments, and select programs that are most likely to
23 provide customer value.

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Program priorities include:

- All MPSC reporting – providing reporting metrics and data as required or requested by internal stakeholders;
- Estimated Time of Restoration (“ETR” – utilizing Machine Learning in real time, to provide an ETR when a customer loses power, on blue sky days through catastrophic storms;
- Customer Experience Index – supporting the Company’s top level goal of consolidation of all live and automated phone calls, app and web traffic, and customer experience surveys across all channels;
- Data Automation – centralizing all data outputs from the dozens of source systems and properly storing and maintaining in a centralized resource;
- Data Quality – ensuring accurate Customer information for address, email, phone numbers, etc. - improving communication accuracy;
- Data Visualization – the execution of all metrics tracked by both Customer Operations and Customer Experience; and
- Problem Solving – deep dive analysis into the most granular data to support the improvement of customer impacting metrics.

Analytics and Outreach efforts allow the Company to more efficiently utilize its resources, target communications to precise customer segments, and select, develop, and implement programs that are most likely to provide customer value. Work performed by this team is utilized across and beyond the entirety of the CX&O organization.

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1 To continue this work, the Company is projecting approximately \$2.88 million in
2 O&M expenses for the test year ending April 30, 2027. As shown on Exhibit A-53
3 (JRB-2), this represents an increase in O&M expenses of \$763,000 from the \$2.31 million
4 expended in 2024. The primary driver of this is an increase in labor-related costs in the
5 test year.

6 **B. Billing and Payment**

7 **Q. Please provide an overview of Billing and Payment.**

8 A. Billing and Payment is responsible for leveraging customer feedback to ensure payment
9 processes are simple and consistent, monthly energy bills are accurate and easy to
10 understand, and customers receive their bills in a timely fashion. The work in this
11 department is divided between Customer Billing and Customer Payment programs. The
12 Company is projecting \$11.4 million in O&M expenses for the test year ending April 30,
13 2027. As shown on Exhibit A-53 (JRB-2), this represents an increase in O&M expenses
14 of approximately \$1.2 million from the \$10.1 million expended in 2024. This increase is
15 mainly due to increases in postage, materials, and labor costs.

16 **1. Customer Billing**

17 **Q. Please provide an overview of Customer Billing.**

18 A. Customer Billing manages the exceptions process--a quality control process designed to
19 (1) review unusual bills (both digital and paper), and/or (2) bill for unique programs before
20 they are sent to customers. The review may involve contacting customers to gather
21 additional information or to inform them of a potential billing issue. Bills may be corrected
22 through the billing adjustment process, or meters may be reread as part of the validation
23 process. Rigorous efforts to ensure every customer bill is accurate results in the Customer

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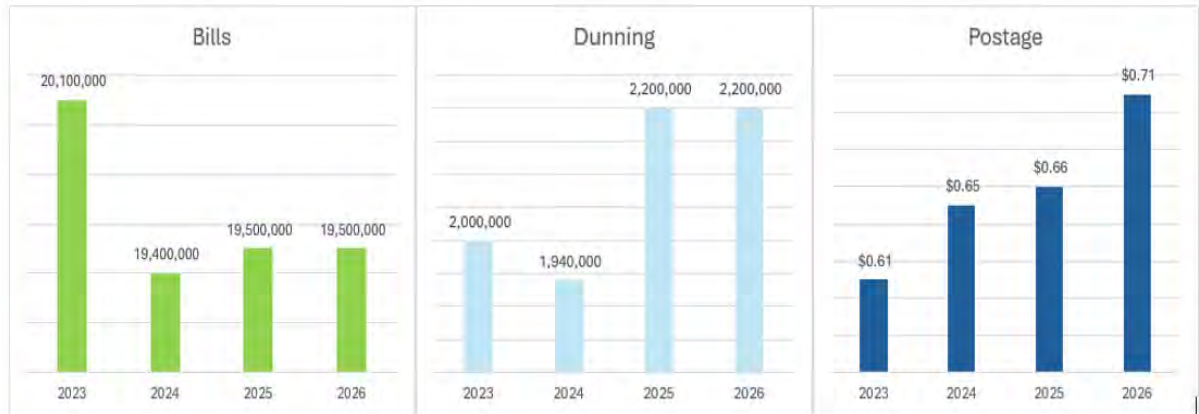
1 Billing team continually optimizing its processes and technology to aid in the billing
2 exception review. Ensuring that customers receive the right bill every time is critical. To
3 continue this work, the Company is projecting \$10.4 million of O&M expenses for the test
4 year ending April 30, 2027. As shown on Exhibit A-53 (JRB-2), this represents an increase
5 of \$1.1 million from the \$8.9 million expended in 2024, due to USPS postage increases in
6 2024 and 2025.

7 **Q. Please explain the costs within Customer Billing.**

8 A. The cost for stationery, forms, and postage related to the Company's billing and dunning
9 communication processes is included in Customer Billing. In 2024, the Company mailed
10 nearly 19.44 million paper bills, and 1.94 million dunning notices. Although bills and
11 dunning numbers have decreased over time, dunning notices are projected to increase
12 significantly, and paper bill numbers are projected to stay significant. Additionally,
13 postage rates have seen a 7.4% increase in 2024, with another scheduled 7.8% increase
14 scheduled to commence in 2025. Consequently, costs associated with billing continue to
15 increase.

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Figure 1. Current and Projected Dunning Numbers and Postage Costs



To mitigate cost increases, the Company has taken action to increase customer enrollment in electronic billing, or eBill. Consumers Energy has successfully increased eBill participation from <27% in 2017 to 48% as of the fourth quarter of 2023. This growth has offset postage costs by over \$2.5 million annually by reducing the number of pieces mailed.

2. Customer Payment Programs

Q. Please describe the CX&O Customer Payment Programs group.

A. Customer payments are among the most sensitive and frequent touchpoints the Company has with its customers, with approximately 34 million payments made annually. The Company's Customer Payment Program group 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

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customer expectations and to maintain a single set of customer-friendly payment rules that apply across all payment options.

Q. Please describe the costs associated with the Customer Payment Programs.

A. The Company is projecting \$1.4 million in the test year O&M expenses shown on Exhibit A-53 (JRB-2). This represents a \$147,000 increase from the \$1.2 million expended in 2024. The increase is mostly due to increasing labor and contractor (Paymentus and lockbox) costs.

Q. What are the anticipated payment processing fee costs for the test year?

A. Within the \$1.4 million of Customer Payment Programs test year O&M expense, the Company is projecting \$200,634 in payment processing fees O&M expenses for the test year. Additional payment-related fees include bank lock box fees in the amount of \$379,440, approximately \$488,432 in Direct Payment Office (“DPO”)-related payment fees, and \$336,608 for the Billing & Payment Program Support team.

Q. Are there additional changes to the way the Company collects payment processing fees?

A. As discussed above, the Company has implemented a policy change, resulting in a fee-based model for payments submitted through vendor payment channels.

Q. Does the Company anticipate any revenues generated by assessing payment card service fees to customers continuing to pay with a credit/debit card?

A. No, the Company does not anticipate or forecast any revenue being generated from payment processing fees.

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1 **Q. What are the merchant fees that customers pay for use of credit/debit cards?**

2 A. All customers using credit/debit cards pay a flat fee per transaction. Residential customers
3 pay \$2.99 per transaction and C&I customers pay \$9.99 per transaction, regardless of rate
4 schedule. These fees are paid directly to the third-party payment processor, Paymentus.

5 **Q. Please provide an overview of DPOs.**

6 A. Consumers Energy has eight DPOs around the state of Michigan, all located within existing
7 Company facilities, making them a cost-effective option for customers to pay their bills in
8 person. These offices serve some of the Company's most vulnerable customers, such as
9 seniors and low-income customers, providing them with a community resource that can
10 connect them with billing options and assistance opportunities.

11 **Q. Does the Company offer other in-person payment options in addition to the remaining**
12 **DPOs?**

13 A. Yes. The Company has maintained its relationship with an authorized pay agent, which
14 accepts payments at stations such as Wal-Mart, Kroger, and other associated store fronts.
15 These pay stations serve as de facto DPOs. This provides customers with the continuity
16 and convenience of being able to pay their bill without having to locate a DPO. Customers
17 are charged a fee to pay their bill in these locations, which covers the costs of the processing
18 fee the Company is charged to have this option.

19 **Q. Does the Company itself collect the payment fee?**

20 A. It does not. The authorized pay agent implements and collects the fee from the customer
21 utilizing their services.

1 **Q. What is the payment fee?**

2 A. The payment fee is \$1.50 per transaction, per the agreement between the vendor and the
3 Company.

4 **II. Regression Analysis on Equity of Shutoffs**

5 **Q. Please discuss the Company's analysis related to the equity of shutoffs of residential**
6 **customers?**

7 A. The Commission's final Order in Case No. U-21585 directed the Company to include an
8 analysis of residential shutoffs in the regression analysis that the Company was already
9 conducting into equity issues in distribution reliability. This analysis of residential shutoffs
10 was conducted by the Company as part of the broader regression analysis that Company
11 witness Kelly describes in his direct testimony and which he sponsors as Exhibit A-135
12 (MPK-25). While his testimony and Exhibits A-135 (MPK-25) and A-138 (MPK-28)
13 provide a detailed description and overview of the entire analysis, I will address one finding
14 of that analysis. In particular, the analysis found that when all other modeled variables are
15 held constant increasing Percentage Minority Population in a census tract is statistically
16 significant and associated with increasing disconnection rate.

17 **Q. Do Company employees have access to customer data that identifies race?**

18 A. The Company does purchase aggregate customer data from Acxiom that has racial
19 identifiers, but the racial identity data is not accessible at the customer account level.
20 Consequently, a disconnection strategy cannot be based on racial data.

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1 Authorized Consumers Energy employees also have access to very specific
2 customer data as posted in its Customer Privacy notice⁵ and highlighted in both its
3 Electric and Natural Gas service tariffs.⁶ Race is not a data collection point.

4 **Q. Given that race data is not a factor in the Company's disconnection strategy, how**
5 **does the Company intend to respond to the referenced regression analysis finding?**

6 A. The Company takes seriously its commitment to providing equitable treatment to all
7 customers and is concerned by any finding that indicates that customers in minority groups
8 might face shutoffs at an inequitable rate. The Commission's requirement to conduct this
9 analysis was issued approximately two months prior to the filing date of the instant case,
10 and the analysis itself was only completed approximately three weeks prior. The Company
11 is therefore still analyzing these results to determine the next steps but plans to do so
12 expeditiously by standing up an internal problem-solving process in June 2025. The
13 Company intends to identify causes, impact, and effective countermeasures to address the
14 analysis and will provide relevant updates as the process is completed.

15 **Q. Does this complete your direct testimony?**

16 A. Yes.

⁵ <https://www.consumersenergy.com/privacy>

⁶ <https://www.consumersenergy.com/-/media/CE/Documents/rates/electric-rate-book.pdf#page=125> and
<https://www.consumersenergy.com/-/media/CE/Documents/rates/gas-rate-book.pdf#page=101>

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U- 21870

DIRECT TESTIMONY

OF

THOMAS P. CLARK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

THOMAS P. CLARK
U-21870 DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

2 A. My name is Thomas P. Clark, and my business address is 1945 West Parnall Road, Jackson,
3 Michigan 49201.

4 **Q. By whom are you employed?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

6 **Q. In what capacity are you employed?**

7 A. I am the Executive Director of the Clean Energy Project Development (“CEPD”)
8 Department.

9 **Q. Please describe your educational background.**

10 A. I received the degree of Bachelor of Science in Engineering from Western Michigan
11 University in 2004. Since 2010, I have been a Registered Professional Engineer in the state
12 of Michigan. In December 2016, I received the degree of Master of Business
13 Administration from the Ross School of Business at the University of Michigan Ann Arbor.

14 **Q. Please describe your business experience.**

15 A. In August 2004, I joined Consumers Energy as an Electric System Owner. In 2005,
16 I accepted a position as an Engineer in Transactions and Resource Planning responsible for
17 administration of the Resource Conservation Plan and the Qualified Facility Reduced
18 Dispatch Agreements. In this role, I assisted with proposal evaluation and the
19 administration of power purchase contracts. In early 2009, I took on responsibilities
20 associated with the Company’s Renewable Energy Plan (“RE Plan”), including the
21 calculation of the Transfer Price associated with renewable energy and capacity and
22 Renewable Energy Credit tracking and forecasting. In June 2013, I was assigned to the
23 Smart Energy Department where I was responsible for the development and

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1 implementation of demand response programs associated with the Company's deployment
2 of Advanced Metering Infrastructure. In March 2015, I accepted the role of Manager of
3 the Company's Resource Planning Department where I was responsible for all the
4 Company's short-, mid-, and long-term electric generation resource planning, including the
5 development of the Company's Integrated Resource Plans ("IRP"). In July 2017, I added
6 Real-Time and Day-Ahead Midcontinent Independent System Operator, Inc. ("MISO")
7 Market Operations to my Resource Planning responsibilities. In March 2021, I was
8 promoted to Executive Director of Electric Supply where I had responsibility for
9 purchasing and transport functions for fuel for electric generation, interaction in the MISO
10 markets, Power Supply Cost Recovery ("PSCR") activities, wholesale settlement and
11 transaction functions, and contract strategy functions including distribution agreements,
12 solicitations for energy and capacity, renewable energy compliance, and distributed
13 generation programs. In December 2021, I was assigned my current role of Executive
14 Director of the CEPD where I am responsible for the development and acquisition of all
15 Company-owned renewable energy resources, including solar, wind, and storage projects.

16 **Q. Have you previously presented testimony before the Michigan Public Service**
17 **Commission ("MPSC" or the "Commission")?**

18 **A.** Yes. I provided testimony in the following cases:

- 19 • Case No. U-15675-R, the Company's 2009 PSCR Reconciliation;
- 20 • Case No. U-16300, the Company's 2009 Renewable Cost Reconciliation;
- 21 • Case No. U-16543, the Company's RE Plan Amendment;
- 22 • Case No. U-16045-R, the Company's 2010 PSCR Reconciliation;
- 23 • Case No. U-16301, the Company's 2010 Renewable Cost Reconciliation;
- 24 • Case No. U-16581, the Company's Biennial RE Plan Review;

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- Case No. U-16432-R, the Company’s 2011 PSCR Reconciliation;
- Case No. U-16655, the Company’s 2011 Renewable Cost Reconciliation;
- Case No. U-17301, the Company’s 2013 Biennial RE Plan Review;
- Case No. U-17321, the Company’s 2012 Renewable Cost Reconciliation;
- Case No. U-18250, the Company’s application for a financing order approving the securitization of qualified costs and related approval;
- Case No. U-18322, the Company’s 2017 Electric Rate Case (“ERC”);
- Case No. U-20165, the Company’s 2018 IRP;
- Case No. U-20963, the Company’s 2021 ERC;
- Case No. U-21090, the Company’s 2021 IRP;
- Case No. U-21224, the Company’s 2022 ERC;
- Case No. U-21389, the Company’s 2023 ERC;
- Case No. U-21585, the Company’s 2024 ERC; and
- Case No. U-21816, the Company’s RE Plan Amendment.

Q. What is the purpose of your direct testimony in this proceeding?

A. My testimony provides background, informational updates and support for capital expenditures associated with new Battery Energy Storage System (“BESS”) projects. Specifically, my testimony discusses two BESS projects:

- Iosco BESS Project – a 30 MW/120 MWh battery located in Oscoda Township, Iosco County, that was initially approved in Case No. U-21585, the Company’s 2024 ERC. The Iosco BESS Project is being developed and constructed to support the 75 MW BESS Deployment Program approved as part of the settlement of the 2021 IRP; and
- Weadock BESS Project – 45 MW/180 MWh battery located in Hampton, Township, Bay County, that was initially approved in Case No. U-21585, the Company’s 2024 ERC. The Weadock BESS Project is being developed and constructed to support the 75 MW BESS Deployment Program approved as part of the settlement of the 2021 IRP.

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1 **Q. Please detail how your direct testimony is related to the direct testimony of other**
2 **Company witnesses.**

3 A. The Iosco BESS and Weadock BESS projects associated capital spending supported in my
4 testimony are a subset of the overall generation capital expenditure plan explained and
5 sponsored by Company witness Richard T. Blumenstock and presented in Exhibit A-12
6 (RTB-3), Schedule B-5.2.

7 **Q. Are you sponsoring any exhibits with your direct testimony?**

8 A. Yes, I am sponsoring the following exhibits:

9 Exhibit A-54 (TPC-1) Weadock BESS Project – Milestone
10 Schedule;

11 **Confidential** Exhibit A-55 (TPC-2) Weadock BESS Project – Substation
12 Transformer Agreement by and between
13 Virginia Transformer Company and
14 Consumers Energy Company, dated
15 March 1, 2024;

16 **Confidential** Exhibit A-56 (TPC-3) Weadock BESS Project – Purchase Order by
17 and between Virginia Transformer Company
18 and Consumers Energy Company, dated
19 March 7, 2024;

20 **Confidential** Exhibit A-57 (TPC-4) Weadock BESS Project – EPC Contract
21 between Rauhorn Electric, Inc. and
22 Consumers Energy Company, dated
23 August 2, 2024;

24 **Confidential** Exhibit A-58 (TPC-5) Weadock BESS Project – Major
25 Procurement Contract between Our Next
26 Energy, Inc. and Consumers Energy, dated
27 August 2, 2024;

28 **Confidential** Exhibit A-59 (TPC-6) Weadock BESS Project – Contract Change
29 Order #1 to the Major Procurement Contract
30 by and between Our Next Energy, Energy
31 Vault, Inc. and Consumers Energy
32 Company, dated December 18, 2024;

33 Exhibit A-60 (TPC-7) Iosco BESS Project – Milestone Schedule;

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Confidential Exhibit A-61 (TPC-8) Iosco BESS Project – Substation Transformer Agreement by and between Virginia Transformer Company and Consumers Energy Company, dated March 1, 2024;

Confidential Exhibit A-62 (TPC-9) Iosco BESS Project – Purchase Order by and between Virginia Transformer Company and Consumers Energy Company, dated March 7, 2024;

Confidential Exhibit A-63 (TPC-10) Iosco BESS Project – EPC Contract between Rauhorn Electric, Inc. and Consumers Energy Company, dated August 2, 2024;

Confidential Exhibit A-64 (TPC-11) Iosco BESS Project – Major Procurement Contract between Our Next Energy, Inc. and Consumers Energy Company dated August 2, 2024; and

Confidential Exhibit A-65 (TPC-12) Iosco BESS Project – Contract Change Order #1 to the Major Procurement Contract between Our Next Energy, Energy Vault, Inc. and Consumers Energy Company, dated December 18, 2024.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes. The Major Procurement Contracts for the Iosco BESS and Weadock BESS projects were negotiated by my organization and executed in the normal course of business. These contracts were also signed by an officer of Consumers Energy.

IRP BESS 75 MW DEPLOYMENT PROGRAM

Q. Please provide an overview of the Company's IRP BESS 75 MW Deployment Program.

A. In Case No. U-21090, the Company's 2021 IRP, and corresponding Settlement Agreement, dated June 23, 2022, the Company agreed to add 75 MW of battery capacity between 2024 and 2027.

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1 **Q. What requirements were requested for inclusion in the Company's battery**
2 **deployment program?**

3 A. As presented in the rebuttal testimony of Company witness Blumenstock in Case No.
4 U-21090 the Company proposed the following requirements for its battery deployment
5 program:

- 6 • The Company will use the battery resources included in the program in
7 isolation or in combination with the other resource sets identified in the
8 PCA (i.e., solar, Energy Waste Reduction, Demand Response);
- 9 • The battery resources, and any battery plus resource combinations, are
10 to be owned by Consumers Energy to facilitate an expedited pace of
11 installation and learnings;
- 12 • The Company will conduct an all-battery request for proposal ("RFP")
13 to develop the most economic battery projects. The RFP will consider
14 Company bid resources as well as Build Transfer Agreements and other
15 similar arrangements;
- 16 • The battery resources will not be used to set the Public Utility
17 Regulatory Policies Act of 1978 full avoided cost rates and therefore,
18 will not be subject to the same competitive procurement guidelines as
19 the IRP solicitations;
- 20 • The Company will have flexibility to procure solar plus storage options
21 in the above discussed solicitations;
- 22 • The Company will have the flexibility to adjust amounts of annual
23 battery deployment based upon economics of the bid proposals resulting
24 from the RFP; and
- 25 • To the extent possible, siting of projects will be implemented in
26 localized areas identified as providing potential benefits to the
27 distribution systems' reliability, resiliency, and performance with a
28 focus on vulnerable communities.

29 **Q. What has been the Company's progress with its battery deployment program?**

30 A. The Company conducted customer outreach, identified two specific project sites, issued
31 two battery deployment solicitations, evaluated the proposals, executed all necessary

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contracts and procurements, and began the design process for both projects. Both projects were presented in the Company's 2024 Electric Rate Case.

Q. Please describe the Weadock BESS Project?

A. The Weadock BESS Project is a 45 MW/180 MWh lithium-ion battery energy storage system interconnected at the Weadock Substation on the Company's 46 kV high voltage distribution system located in Essexville, Bay County. The purpose of this project is to provide localized grid support and provide data regarding how battery storage could benefit the reliability, resiliency, and performance of the high voltage distribution system as well as provide energy arbitrage and firm dispatchable capacity in the MISO market. This project will be constructed on Company-owned property within the Karn/Weadock Generating complex. The project has been executed utilizing Major Procurement Agreements for Engineering, Procurement, and Construction ("EPC"); Substation Transformer Unit; and Battery Supply Agreements ("BSAs").

Q. Does this project require Board of Directors approval?

A. No. The project does not require Board of Director approval.

Q. What is the project schedule?

A. The Weadock BESS Project is scheduled to begin commercial operation on December 21, 2026. See Exhibit A-54 (TPC-1) for further detail regarding the project schedule.

Q. Which Major Procurement Agreements has the Company executed to date?

A. The Company has executed the Substation Transformer Unit agreement, EPC, and BSA. **Confidential** Exhibit A-55 (TPC-2) and **Confidential** Exhibit A-56 (TPC-3) references the Substation Transformer Agreement and associated Purchase Order with Virginia Transformer, dated March 1, 2024, and March 7, 2024, respectively. **Confidential** Exhibit

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1 A-57 (TPC-4) is the EPC Agreement with Rauhorn Electric dated August 2, 2024, and
2 **Confidential** Exhibit A-58 (TPC-5) is the Major Procurement contract with Our Next
3 Energy, Inc. (“Our Next Energy”) dated August 2, 2024.

4 **Q. Have there been any significant changes to these contracts?**

5 A. Yes. Energy Vault, Inc. (“Energy Vault”) will assume the BSA previously executed with
6 Our Next Energy. Energy Vault has agreed to all terms and conditions of the BSA, except
7 as explicitly stated in Contract Change Order #1 (**Confidential** Exhibit A-59 (TPC-6) dated
8 December 18, 2024.)

9 **Q. What necessitated the transition to Energy Vault?**

10 A. Our Next Energy was unable to provide sufficient project financial risk mitigation, as
11 required under the terms of the BSA. Consequently, Our Next Energy contacted Energy
12 Vault, a company with over 300 MW of projects currently under construction and more
13 than 500 MW of deployed BESS and Hybrid Energy Storage Systems (“HESS”), with the
14 intention to have Energy Vault assume the BSA. The Company evaluated Energy Vault’s
15 financial risk and determined that they were well positioned to address the issues present
16 with Our Next Energy.

17 **Q. What is the projected cost of the Weadock BESS Project?**

18 A. Table 1 below represents the Weadock BESS Project’s actual and projected capital
19 spending based on the project schedule.

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Table 1: Iosco and Weadock BESS Capital Expenditure

Line No.	Description		Bridge Year	Test Year	Total Capital
		12/31/2024	16 Months Ending 4/30/2026	12 Months Ending 4/30/2027	
	(a)	(b)	(c)	(d)	(e)
1	Iosco BESS Project	\$ 8.39	\$ 30.05	\$ 11.46	\$ 49.90
2	Weadock BESS Project	\$ 11.95	\$ 40.56	\$ 14.93	\$ 67.45
3					
3	Total	\$ 20.34	\$ 70.61	\$ 26.39	\$ 117.34

The Company projects that it will spend \$40,560,000 in the Bridge Period and \$14,930,000 in the Test Year, bringing the total projected capital expenditures to \$67,450,000. These values are estimated based on the executed Substation Transformer Agreement, BSA, and EPC Contract, along with the Company-approved overheads and loadings.

Q. Why have the project costs increased?

A. The revised and updated costs provide a more precise reflection of project costs and loadings based upon the current commercial operation dates.

Q. Has the Company included any contingency in the projected capital expenditure for the project?

A. No. Company witness Blumenstock will address the Company's position regarding contingency for Company-owned projects in his testimony.

Q. Please describe the Iosco BESS Project?

A. The Iosco BESS Project is a 30 MW/120 MWh lithium-ion battery energy storage system interconnected at the Iosco Substation on the Company's 46 kV high voltage distribution system located near the City of Oscoda, Iosco County. The purpose of this project is to provide localized grid support and provide data regarding how battery storage could benefit the reliability, resiliency, and performance of the high voltage distribution system as well as provide energy arbitrage and firm dispatchable capacity in the MISO market. This

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1 project will be constructed on existing Company-owned property near the existing Iosco
2 Substation. The project has been executed utilizing Major Procurement Agreements for
3 EPC; Substation Transformer Unit; and BSA.

4 **Q. Does this project require the Board of Directors approval?**

5 A. No. The project does not require the Board of Directors Approval.

6 **Q. What is the project schedule?**

7 A. The Iosco BESS Project is scheduled to begin commercial operation on December 21,
8 2026. See Exhibit A-60 (TPC-7) for further detail in regard to the project schedule.

9 **Q. Which Major Procurement Agreements has the Company executed to date?**

10 A. The Company has executed the Substation Transformer Unit agreement, EPC, and BSA.
11 **Confidential** Exhibit A-61 (TPC-8) and **Confidential** Exhibit A-62 (TPC-9) references the
12 Substation Transformer Agreement and associated Purchase Order with Virginia
13 Transformer, dated March 1, 2024 and March 7, 2024, respectively. **Confidential** Exhibit
14 A-63 (TPC-10) is the EPC Agreement with Rauhorn Electric dated August 2, 2024 and
15 **Confidential** Exhibit A-64 (TPC-11) is the Major Procurement Contract with Our Next
16 Energy dated August 2, 2024.

17 **Q. Have there been any significant changes to these contracts?**

18 A. Yes. Energy Vault, Inc. will assume the BSA previously executed with Our Next Energy.
19 Energy Vault has agreed to all terms and conditions of the BSA, except as explicitly stated
20 in Contract Change Order #1 **Confidential** Exhibit A-65 (TPC-12) dated December 18,
21 2024.

1 **Q. What necessitated the transition to Energy Vault?**

2 A. Our Next Energy was unable to provide sufficient project financial risk mitigation, as
3 required under the terms of the BSA. Consequently, Our Next Energy contacted Energy
4 Vault, a company with over 300 MW of projects currently under construction and more
5 than 500 MW of deployed BESS and HESS, with the intention to have Energy Vault
6 assume the BSA. The Company evaluated Energy Vault's financial risk and determined
7 that they were well positioned to address the issues present with Our Next Energy.

8 **Q. What is the projected cost of the Iosco BESS Project?**

9 A. Table 1 above provides the Iosco BESS Project's actual and projected capital spending
10 based on the project schedule. The Company projects that it will spend \$30,050,000 in the
11 Bridge Period, \$11,460,000 in the Test Year bringing the total projected capital
12 expenditures to \$49,900,000. These values are estimated based on the executed Substation
13 Transformer Agreement, BSA, and EPC Contract, along with the Company-approved
14 overheads and loadings.

15 **Q. Why have the project costs increased?**

16 A. The revised and updated costs provide a more precise reflection of project costs and
17 loadings based upon the current commercial operation dates.

18 **Q. Has the Company included any contingency in the projected capital expenditure for
19 the project?**

20 A. No. Company witness Blumenstock will address the Company's position regarding
21 contingency for Company-owned projects in his testimony.

22 **Q. Does this conclude your direct testimony?**

23 A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

LAURA M. CONNOLLY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

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Q. Please state your name and business address.

A. My name is Laura M. Connolly, 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 Director of Regulated Pricing in the Rates and Regulation Department.

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Business Administration degree in Finance in December 2000 from the University of Michigan – Flint. In January 2001, I joined Consumers Energy as a Rate Analyst in the Revenue Requirements section of the Rates Department, where I held positions of increasing responsibility. I joined the Cost Analysis, Pricing and Tariff section of the Rates Department in 2012 and was promoted to Director of Regulated Pricing in July 2021.

Q. What are your responsibilities as Director of Regulated Pricing for Consumers Energy?

A. In my current role I oversee the development of the Company’s Cost-of-Service Study (“COSS”), load research, rate design, and other rate-related analyses.

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-12575-R Gas Cost Recovery Reconciliation;

Case No. U-13220 Gas Cost Recovery Plan;

Case No. U-13570 Gas Cost Recovery Plan;

Case No. U-13570-R Gas Cost Recovery Reconciliation;

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1	Case No. U-13730	Gas General Rate Case;
2	Case No. U-13916	Gas Cost Recovery Plan;
3	Case No. U-13917-R	Power Supply Cost Recovery (“PSCR”) Reconciliation;
4	Case No. U-14274-R	PSCR Reconciliation;
5	Case No. U-14347	Electric General Rate Case;
6	Case No. U-14403	Gas Cost Recovery Plan;
7	Case No. U-14403-R	Gas Cost Recovery Reconciliation;
8	Case No. U-14701-R	PSCR Reconciliation;
9	Case No. U-14716	Gas Cost Recovery Plan;
10	Case No. U-14716-R	Gas Cost Recovery Reconciliation;
11	Case No. U-15001-R	PSCR Reconciliation;
12	Case No. U-15415-R	PSCR Reconciliation;
13	Case No. U-15454	Gas Cost Recovery Plan;
14	Case No. U-15675-R	PSCR Reconciliation;
15	Case No. U-16045	PSCR Plan;
16	Case No. U-16045-R	PSCR Reconciliation;
17	Case No. U-16736	Energy Optimization Reconciliation;
18	Case No. U-16432	PSCR Plan;
19	Case No. U-16432-R	PSCR Reconciliation;
20	Case No. U-16890	PSCR Plan;
21	Case No. U-17197	Gas General Rate Case;
22	Case No. U-17281	Energy Optimization Reconciliation;
23	Case No. U-17601	Energy Optimization Reconciliation;
24	Case No. U-17688	Public Act 169 of 2014;
25	Case No. U-17735	Electric General Rate Case;

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1	Case No. U-17990	Electric General Rate Case;
2	Case No. U-18322	Electric General Rate Case;
3	Case No. U-20134	Electric General Rate Case;
4	Case No. U-20102	Electric Tax Credit A;
5	Case No. U-20286	Electric Tax Credit B;
6	Case No. U-20563	Demand Response Reconciliation;
7	Case No. U-20889	Securitization of Karn Units 1 and 2;
8	Case No. U-20803	PSCR Reconciliation;
9	Case No. U-21308	Gas General Rate Case;
10	Case No. U-21049	PSCR Reconciliation;
11	Case No. U-21321	Energy Waste Reduction Plan;
12	Case No. U-21258	PSCR Reconciliation;
13	Case No. U-21424	PSCR Reconciliation;
14	Case No. U-21585	Electric General Rate Case; and
15	Case No. U-21859	Ex Parte Approval of Certain Amendments to Rate GPD.

16 **Q. What is the purpose of your direct testimony?**

17 A. The purpose of my direct testimony is to present the Company's proposed rate design that
18 will result in electric revenues sufficient to collect the total revenue requirement proposed
19 by the Company in this case.

20 **Q. Are you sponsoring any exhibits?**

21 A. Yes. I am sponsoring the following exhibits:

22	Exhibit A-16 (LMC-1)	Schedule F-2.0	Summary of Present and Proposed Revenues
23			by Rate Schedule;
24	Exhibit A-16 (LMC-2)	Schedule F-2.1	Calculation of Rate Design Targets;
25	Exhibit A-16 (LMC-3)	Schedule F-3.0	Present and Proposed Revenue Detail;

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1	Exhibit A-16 (LMC-4)	Schedule F-4.0	Comparison of Present and Proposed
2			Monthly Bills;
3	Exhibit A-66 (LMC-5)		Demand Response (DR) Surcharge;
4	Exhibit A-67 (LMC-6)		Electric Rate Case (ERC) Deferral
5			Surcharge;
6	Exhibit A-68 (LMC-7)		Investment Recovery Mechanism (IRM)
7			Surcharge;
8	Confidential Exhibit A-69 (LMC-8)		Long-Term Industrial Load Retention Rate
9			(LTILRR) Revenues; and
10	Confidential Exhibit A-70 (LMC-9)		Large Economic Development Rate (LEDLRR)
11			Revenues.

12 **Q. Were these exhibits prepared by you or under your supervision?**

13 A. Yes.

14 **Q. How is your direct testimony organized?**

15 A. My direct testimony is organized as follows:

16 I. RATE DESIGN OVERVIEW

17 II. RATE DESIGN PROPOSALS

18 III. SURCHARGES

19 **I. RATE DESIGN OVERVIEW**

20 **Q. Please describe the primary objectives of rate design.**

21 A. Consistent with the rate designs approved in prior cases, I used the following four key
22 objectives to inform my rate design in this case. My first objective was to adhere to the
23 cost of service in accordance with the requirements set forth in MCL 460.11. I did deviate
24 from the COSS in a couple of instances and will further elaborate on my rationale for doing
25 so later. My second objective was to design rates that encourage the efficient use of the
26 Company's electric system. This means setting rates that accurately reflect the type of cost
27 (fixed versus variable) as well as the temporal nature of certain costs, such as the increased

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1 cost of providing energy during peak seasons and times of day. My third objective was to
2 design rates that promote a favorable business climate. My fourth objective was to design
3 stable rates that provide the Company with a fair opportunity to collect its revenue
4 requirement.

5 **Q. Please describe the cost of service requirements set forth in MCL 460.11.**

6 A. MCL 460.11 requires electric utilities to design rates that reflect the cost of providing
7 service to each customer class. In other words, costs assigned to one class cannot be
8 reassigned to another without cost justification. The intent of this being to prevent, or at
9 the very least limit, interclass subsidies. However, this does not completely remove the
10 utility's ability to maintain crossing-points between rates within a class and to make other
11 adjustments to deviate from the COSS in some instances. I have identified these deviations
12 as adjustments to the class COSS in Exhibit A-16 (LMC-2), Schedule F-2.1.

13 **Q. Please describe your reasons for making these adjustments.**

14 A. Consistent with prior electric rate cases, I am recommending six adjustments to the
15 assignment of costs across the various rate classes and schedules as part of rate design. The
16 first standard adjustment, shown on line 3 of Exhibit A-16 (LMC-2), Schedule F-2.1,
17 reflects the difference between the market cost of production capacity collected from large
18 standby customers taking service under Rate GSG-2 and the embedded cost of capacity
19 allocated to them in the COSS. Two similar adjustments—the second and third—are made
20 for both production energy and transmission costs, shown on lines 7 and 13, respectively.
21 In total, these three adjustments suggest that large standby customers pay less under the
22 market-based rate design structure for production and transmission standby service than
23 they would under an embedded cost of service design.

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1 The fourth standard adjustment, shown on line 18, is used to correct for an over
2 allocation of substation costs to voltage levels 1 and 2 rates as part of the COSS. In the
3 2019 electric rate case, Case No. U-20134, it was brought to the Company's attention that
4 it was inadvertently over allocating substation costs to the higher voltage level rates by
5 excluding customer-owned substations from its COSS. To remedy this issue, the Company
6 agreed to reassign the portion of substation costs by allocating those costs to customers
7 who owned their substation in the COSS as part of rate design. The easiest way to
8 accomplish this was to allocate the substation ownership credits across the rate classes
9 based on the distribution allocators developed in the COSS.

10 The fifth adjustment, shown on line 19, reflects the life line credits (senior citizen
11 and low-income) that have traditionally been supported by all customer classes. Unlike
12 the other approved adjustments, however, the life line adjustment is not cost justifiable.
13 Instead, it is based on the Commission's authority to approve special senior citizen and
14 low-income rates granted under MCL 460.11.

15 The sixth adjustment, shown on line 2, reflects the removal of the Demand
16 Response ("DR") revenue requirement calculated by Company witness Patrick D. Daly in
17 Exhibit A-83 (PDD-59) and allocated to each rate schedule by Company witness Emily A.
18 Davis in Exhibit A-89 (EAD-5), from base rates. The Order in Case No. U-21585 approved
19 the Company's proposal to consolidate the DR program costs, customer credits, financial
20 incentives, and regulatory balances into an all-encompassing surcharge. This adjustment
21 is described further by Company witness Alex M. Gast.

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1 **Q. Please explain your approach in designing rates to collect the Company's production**
2 **costs.**

3 A. Production is comprised of both fixed and variable costs, which are separated in the COSS
4 between capacity and energy costs. Production capacity represents the cost of a generating
5 plant and having it stand ready to serve customer demand over an extended period of time
6 (annually) or at a certain hour (peak). Conversely, production energy represents the cost
7 of running these plants and is usually attributed to fuel expenses. Traditionally, the
8 Company has used a combination of historical prices based on the Midcontinent
9 Independent System Operator, Inc. ("MISO") market to estimate the energy price spread
10 of providing service during different time periods.

11 **Q. Are you recommending any changes to the methodology used to calculate the**
12 **production energy price spreads as part of the rate design?**

13 A. No. Consistent with the method used in the prior electric rate case, Case No. U-21585, the
14 Company is using the weighted average hourly Locational Marginal Pricing ("LMP") to
15 calculate the energy charge spreads for the various Time-of-Use ("TOU") rates. This
16 weighting of hourly LMP values based on the corresponding hourly energy use better
17 reflects the value of energy in each time period.

18 **Q. Please describe the calculation of the LTILRR revenues shown in your Confidential**
19 **Exhibit A-69 (LMC-8).**

20 A. The first page of Confidential Exhibit A-69 (LMC-8) contains the forecasted test year
21 billing determinants and monthly charges based on the approved LTILRR tariff and
22 customer contract. The second page of Confidential Exhibit A-69 (LMC-8) calculates the
23 test year miscellaneous revenues, provided to Company witness Eugène M. Breuring,

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1 based on the information from the first page and the forecasted production and transmission
2 costs sponsored by Company witness Megan L. Metz.

3 **Q. What happens if actual LTILRR electric sales are less than the level forecasted by the**
4 **Company in this case?**

5 A. Any changes in the electric sales and power supply costs associated with the LTILRR are
6 included in the Company's annual PSCR plans and reconciliations. For example, if the
7 actual LTILRR electric sales are lower than the levels forecasted in this case, then the
8 Company would include the lower power supply miscellaneous revenue as part of the
9 LTILRR payment in its PSCR reconciliation. Similarly, a higher sales level would result
10 in a higher payment in the PSCR reconciliation.

11 **Q. Is the Company recommending any changes to the LTILRR in this case?**

12 A. No, it is not.

13 **Q. Please describe the calculation of the LEDR revenues shown in your Confidential**
14 **Exhibit A-70 (LMC-9).**

15 A. In Case No. U-21160, the MPSC approved the LEDR tariff and inclusion of the related
16 LEDR revenues in general rate cases as miscellaneous revenue. Confidential Exhibit A-70
17 (LMC-9) contains the forecasted test year billing determinants and monthly charges based
18 on the approved LEDR tariff and forecasted customer usage during the test year. The
19 calculated LEDR revenues are picked up by Company witness Breuring as part of total
20 miscellaneous revenue in Exhibit A-15 (EMB-3), Schedule E-2.

21 **Q. Is the Company proposing any changes to LEDR in this case?**

22 A. Yes. The changes to LEDR are discussed below.

1 **II. RATE DESIGN PROPOSALS**

2 **A. Residential**

3 **Q. Please explain your approach in designing the Company’s residential customer class**
4 **rates.**

5 A. The Company is recommending the Commission maintain the currently approved
6 residential rate design structure. My overall objective in designing the residential rates was
7 to continue providing a sense of stability for this class by maintaining the existing rate
8 structures for each option—i.e. Residential Summer On-Peak Basic Rate (“RSP”),
9 Residential Smart Hours Rate (“RSH”), Residential Nighttime Savers Rate (“RPM”), and
10 Residential Service Secondary Non-Transmitting Meter Rate (“RSM”). There are no
11 changes proposed to the structure or type of charges. Also, the collection of charges within
12 the available rate options were evaluated based on how each fit individually and
13 collectively within the class. For example, the summer on-peak charges assessed in all
14 three residential TOU options were set equal since each covered the same period and are
15 intended to inform customers about the cost of providing power during that period.

16 **Q. What is the monthly residential bill impact under your proposed rate design?**

17 A. The average monthly residential customer bill is projected to increase 11% from
18 approximately \$132 per month to \$146 per month. The monthly customer typical bill
19 impacts for each rate schedule are also shown in Exhibit A-16 (LMC-4), Schedule F-4.0.

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1 **Q. How does the residential monthly bill under your proposed rate design compare with**
2 **the national average bill projected by the Energy Information Administration**
3 **(“EIA”)?**

4 A. The national average residential electric bill from the EIA is projected to be \$154 per month
5 in 2026, which is approximately \$8 more than the \$146 per month projected for the
6 Company’s customers. The Company also offers customers various payment plans and
7 ways to reduce their energy bills through its residential assistance, energy efficiency, and
8 DR programs. In addition, customers interested in proactively managing their energy bills
9 can use many of the programs and digital tools the Company provides; including the online
10 energy dashboard and billing detail to understand how energy is used throughout the day,
11 tips for reducing energy waste, bill forecast trends, and the rate advisor tool to identify
12 actions that can be taken to reduce their bills.

13 **Q. Is the Company proposing any change to the Residential Smart Meter Opt Out Fees?**

14 A. Yes. As discussed in the testimony of Company witness Michael P. Kelly, the Order in
15 Case No. U-21585 directed the Company to re-evaluate its advanced metering
16 infrastructure opt-out charges and include the results in its next case. As such, Company
17 witness Kelly is proposing to update the Residential Smart Meter Opt-Out fee. That update
18 is reflected in Exhibit A-16 (LMC-3), Schedule F-3.0, page 4 of 23, on line 14.

19 **B. Secondary**

20 **Q. Is the Company proposing any changes to the Secondary rate structure?**

21 A. No, the Company is proposing to maintain its current rate structure for secondary
22 customers.

1 C. Primary

2 **Q. Is the Company proposing any changes to the Primary rate structure?**

3 A. The Company is not proposing any changes any changes to the rate structure for Primary
4 Rates GP, GPD, GPTU, or EIP.

5 **Q. Is the Company proposing any changes to LEDR?**

6 A. Yes. First, the Company is proposing to update the production capacity charge based on
7 the latest forecast of MISO Cost of New Entry (“CONE”). Second, the Company is
8 proposing to include a facilities allowance in LEDR. Lastly, the Company is proposing to
9 include a Power Factor adjustment as part of LEDR.

10 **Q. Please describe the Company’s proposal to include a facilities allowance with the**
11 **LEDR.**

12 A. The LEDR was first established by the Commission in Case No. U-21160 and implemented
13 in December 2021. Since its implementation, potential customers have inquired about the
14 availability of a facilities allowance such as that offered under DTE Electric Company’s
15 Rate D13. To better align with other cost-based large customer rate options in Michigan,
16 the Company is proposing to add language to the tariff that would clarify a facilities
17 allowance would be applicable to customers on the rate.

18 **Q. Please describe the Company’s proposed method for calculating the facilities**
19 **allowance for customers.**

20 A. The Company is proposing to calculate the facilities allowance for each prospective
21 customer based on the net present value of margin – defined as the non-energy related costs
22 – based on their expected load over five years of the contract term.

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1 **Q. Does this proposal address the Commission's recommendation in the Case No.**
2 **U-21585 Order?**

3 A. Yes. The Order in Case No. U-21585 stated "in its next electric rate case, if the company
4 believes it beneficial to provide a facilities allowance for Rate LED, Consumers should
5 propose a facilities allowance that includes only distribution and system contribution
6 revenues, not power supply revenues, and that is based on a limited term". The Company's
7 proposal is to base the allowance on the non-energy related costs and limit the margin to
8 five years.

9 **Q. Why does the Company believe five years is an appropriate length of time to use in**
10 **the calculation of the allowance?**

11 A. Five years corresponds to the standard Contribution in Aid of Constructure Allowance
12 offered to standard primary customers.

13 **Q. Is the Company proposing any other changes to LEDR?**

14 A. Yes, the Company is proposing to add an adjustment for Power Factor to LEDR.
15 Consumers Energy must adhere to Power Factor standards for all customers and LEDR
16 customers are no exception.

17 **Q. What type of adjustment for Power Factor is the Company proposing?**

18 A. The Company is proposing to mirror the design of the recently approved Power Factor
19 adjustment for Rates GP, GPD, GPTU, and EIP. However, the Company is proposing to
20 assess penalties for Power Factor between 0.700 and 0.909.

21 **Q. Why is the Company proposing a higher penalty band for LEDR?**

22 A. Consumers Energy must adhere to specific Power Factor requirements outlined in our
23 Distribution-Transmission Interconnection Agreement ("DTIA") with Michigan Electric

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Transmission Company (“METC”), filed at the Federal Energy Regulatory Commission (“FERC”). These requirements state that at system load levels above 90% of peak, the Company must maintain an average Power Factor of 0.98 or better across all interconnection points with METC. Historically, this has not been an issue but customers on LEDR will have larger loads than our current customer base and could have a greater impact on the Company’s total system Power Factor. Thus, the Company is proposing that these customers be held to a higher Power Factor standard.

D. Lighting

Q. Is the Company proposing any change to the streetlighting rate structures?

A. No, the Company is proposing to maintain the current rate structure for the streetlighting rates.

E. Self-Generation

Q. Is the Company proposing any change to the Self-Generation rate structure?

A. No, the Company is proposing to maintain the current rate structure for Rate GSG-2.

F. Power Factor

Q. Is the Company proposing any change to the existing Power Factor credit and penalty structure?

A. Aside from the proposal above to add a Power Factor adjustment to LEDR, the Company is not proposing any further changes to Power Factor. The Commission approved changes to the application of Power Factor in Case No. U-21585. The Company has not yet implemented those changes. Once those changes are implemented, the Company will evaluate their effectiveness and determine if additional changes are necessary.

1 **III. SURCHARGES**

2 **Q. Please describe the method used to develop the DR surcharge proposed by Company**
3 **witness Gast.**

4 A. As discussed by Company witness Gast, the Company is proposing to collect the revenue
5 requirement for the DR Program inclusive of all DR related capital, O&M costs, and rate
6 credits in an all-encompassing surcharge. The DR program costs of \$43,572,000 is
7 calculated by Company witness Daly in Exhibit A-83 (PDD-59) as a revenue requirement
8 and allocated to the various rates in Exhibit A-89 (EAD-5). The removal of the DR revenue
9 requirement from base rates is shown in Exhibit A-16 (LMC-2), Schedule F-2.1, line 2,
10 and the corresponding DR surcharge to collect the test year DR revenue requirement and
11 customer credits is shown on line 23 in the same exhibit.

12 **Q. Please describe the method used to design the ERC Deferral surcharge in this case.**

13 A. As discussed by Company witness Daly, the Company is proposing an ERC Deferral
14 surcharge to recover \$24,327,000 of deferred distribution investments. Similar to the
15 existing surcharge, the deferred costs were allocated to the various rates in Exhibit A-89
16 (EAD-5) and divided by the test year sales to calculate the surcharge.

17 **Q. Describe the IRM proposed by the Company.**

18 A. The proposed IRM would authorize the Company to collect additional revenues associated
19 with incremental distribution reliability spending beginning May 1, 2026 through April 30,
20 2028, with a distinct revenue amount to be collected in each 12-month period, as discussed
21 in the testimony of Company witnesses Heidi J. Myers and Kelly.

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U-21870 DIRECT TESTIMONY

1 **Q. Please describe Exhibit A-68 (LMC-7).**

2 A. Exhibit A-68 (LMC-7) is an illustrative calculation of the proposed IRM surcharge.
3 It shows how the Company proposes to collect the revenue requirements associated with
4 the IRM. The revenue requirements for each class are based on the cost allocation of the
5 revenue requirements in Exhibit A-89 EAD-5). The rate design for the various voltage
6 levels for Rates GP, GPD, EIP, and GPTU are consistent with the rate differentials used in
7 the Company's rate design. The surcharge is based on test year sales and would apply to
8 both Full Service and Retail Open Access customers. With approval of the Commission,
9 these rates would be effective for service rendered on and after May 1, 2026 and service
10 on and after May 1, 2027. The IRM surcharges would continue until rates were modified
11 in the Company's next electric case.

12 **Q. How does the Company propose to reconcile the IRM?**

13 A. As discussed in the testimony of Company witness Myers, the reconciliation of the IRM
14 would be handled in a separate contested proceeding. The Company proposes to reconcile
15 the IRM capital spend on an annual basis. The reconciliation would compare the
16 Company's annual IRM revenue requirement based on the actual incremental investments
17 for that 12-month period against the associated revenue requirement collected from
18 customers by class for that year through the IRM surcharge. If, for example, the actual
19 IRM revenue requirement fell short of the Commission-approved amount collected through
20 the surcharge, then the Company would refund customers the difference.

LAURA M. CONNOLLY
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1 **Q. Would the Company be allowed to increase the surcharges over the amount the**
2 **Commission approved in a final order in this case?**

3 A. No. The Company would only be authorized to implement the surcharges approved by the
4 Commission in this proceeding. However, the Company would implement reductions as
5 ordered by the Commission to modify the surcharge if the amount of the investment was
6 less than the total incremental investment proposed spend amount.

7 **Q. Does this conclude your direct testimony?**

8 A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

AMY M. CONRAD
U-21870 DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is Amy M. Conrad, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. In what capacity are you employed?

A. I am employed as the Director of Compensation Operations for Consumers Energy Company (“Consumers Energy” or the “Company”).

Q. What is your educational background?

A. I graduated from Central Michigan University in 1999 with a Bachelor of Science Degree in Business Administration with a major in Accounting. In addition, I am designated as a Certified Compensation Professional and Certified Executive Compensation Professional by WorlDatWork and a Certified Public Accountant by the Michigan Association of Certified Public Accountants. WorlDatWork is an international professional organization focused on human resources issues, including compensation, benefits, work life, and integrated total rewards to attract, motivate, and retain a talented workforce.

Q. What have your job responsibilities entailed with Consumers Energy?

A. In February 2002, I joined Consumers Energy as a Financial Reporting and Technical Accounting Analyst. My duties included accounting and reporting of equity-based compensation, technical accounting standard research, and preparation of quarterly and annual Securities and Exchange Commission (“SEC”) filings. After eight years of progressing responsibilities in this role, I transferred to the position of Principal Human Resources Consultant. In 2013, I was promoted to the position of Director of Compensation. In this role I had the responsibility for administering Consumers Energy’s compensation function and partnering with Labor Relations on union compensation

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1 matters. This included developing compensation programs designed to attract and retain a
2 qualified workforce for the Company. My duties included gathering of comparable wage
3 and salary data in order to determine how Consumers Energy's pay level compares to the
4 labor market and developing compensation programs that are competitive and deliver pay
5 to employees that is fair and equitable and that motivates employees to perform at their full
6 potential.

7 My responsibilities also consisted of assisting with preparation of materials for the
8 Compensation Committees of the Consumers Energy and CMS Energy Boards of
9 Directors, including the Compensation Discussion & Analysis section of the annual proxy
10 statement for the named executive officers.

11 In May 2018, I took on the role of Director of Executive and Incentive
12 Compensation. My responsibilities consisted of assisting with preparation of materials for
13 the Compensation Committees of the Consumers Energy and CMS Energy Boards of
14 Directors, including the Compensation Discussion & Analysis section of the annual proxy
15 statement for the named executive officers. My responsibilities also included
16 administering the incentive plans for CMS Energy, including Consumers Energy.

17 In August 2023, I took on the role of Manager of Compensation Operations. My
18 Manager of Compensation Operations responsibilities consisted of the implementation of
19 new and revised non-officer compensation programs, policies, and procedures for
20 non-officers to align with the Company's goals and competitive practices. This position is
21 also responsible for ensuring that compensation programs are consistently administered in
22 compliance with internal policies and government regulations. The Manager of
23 Compensation Operations role focuses primarily on the coordination and implementation

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1 of the non-officer merit, incentive, stock administration, survey participation, and ensuring
2 accuracy of data for non-officer programs.

3 In January 2024, I took on the role of Director of Compensation. My Director of
4 Compensation responsibilities consist of the implementation of new and revised officer
5 and non-officer compensation programs, policies, and procedures for officers and
6 non-officers to align with the Company's goals and competitive practices. This position is
7 also responsible for ensuring that compensation programs are consistently administered in
8 compliance with internal policies and government regulations. The Director of
9 Compensation Operations role focuses primarily on the coordination and implementation
10 of the officer and non-officer merit, incentive, stock administration, survey participation,
11 and ensuring accuracy of data for officer and non-officer programs. Lastly, the Director of
12 Compensation consists of assisting with preparation of materials for the Compensation
13 Committees of the Consumers Energy and CMS Energy Boards of Directors, including the
14 Compensation Discussion & Analysis section of the annual proxy statement for the named
15 executive officers. In February 2025, I returned to the Manager of Compensation
16 Operations role which I previously held from August 2023 through December 2023.

17 **Q. Have you previously testified before the Michigan Public Service Commission**
18 **(“MPSC” or the “Commission”)?**

19 A. Yes, I have testified in Case Nos. U-17087, U-17197, U-17643, U-17735, U-17882,
20 U-17990, U-18124, U-18322, U-18424, U-20134, U-20322, U-20650, U-20697, U-21148,
21 U-21224, U-21308, U-21389, U-21490, and U-21806.

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1 **Q. What is the purpose of your direct testimony?**

2 A. The purpose of my direct testimony is to provide support for Consumers Energy’s request
3 for rate recovery for costs of its annual Employee Incentive Compensation Plan (“EICP”)
4 at target levels. The EICP is a form of short-term incentive. Short-term incentive pay is
5 designed to focus and reward performance over periods of approximately one year or less.

6 First, I will discuss Consumers Energy’s overall compensation philosophy. In this
7 section of my direct testimony, I will discuss the importance of paying employees a
8 competitive level of compensation and the reasonableness of the overall compensation
9 levels that the Company is requesting in this case. In addition, I will discuss (i) the fact
10 that EICP compensation is part of an employee’s overall market-based compensation and
11 not in addition to it, and (ii) why Consumers Energy has included EICP at target levels as
12 part of overall market-based compensation.

13 Second, I will discuss the EICP incentives and provide support for the Company’s
14 request for rate recovery in this case related to Consumers Energy’s non-officer and officer
15 operational goal portion of EICP. In my direct testimony, I will discuss the design of the
16 EICP.

17 Third, I will discuss customer-related benefits that result from use of the incentive
18 plans and how customers are best served when Consumers Energy can attract, retain, and
19 motivate a talented workforce with compensation packages that are competitive and fair.
20 Elimination of the EICP would result in Consumers Energy’s employee compensation
21 being below market and would hinder the Company’s ability to attract and retain a qualified
22 workforce that best serves customers.

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1 **Q. Please summarize your conclusions.**

2 A. My conclusions include the following: (i) use of incentive compensation by utility
3 companies is an accepted, common, and reasonable practice; (ii) Consumers Energy's
4 decision to make a portion of compensation at-risk and subject to incentives is reasonable;
5 (iii) the amount of overall compensation included by Consumers Energy in this case is
6 reasonable and is reasonably necessary to attracting and retaining a talented workforce;
7 (iv) incentive compensation is part of the reasonable level of market-based compensation
8 and not in addition to it; (v) recovering costs of Consumers Energy's EICP employee
9 incentive plans will not result in excess rates; (vi) Consumers Energy's EICP performance
10 goals and thresholds provide customer-related benefits; and (vii) the EICP goals provide
11 customer-related benefits at no incremental cost to customers above those included in
12 market-based compensation.

13 **Q. How is the remainder of your direct testimony organized?**

14 A. The remainder of my direct testimony is organized as follows:

15 I. OVERVIEW

16 II. EMPLOYEE COMPENSATION PHILOSOPHY

17 III. INCENTIVE COMPENSATION PLANS

18 A. Description of Incentive Plans

19 B. Assessment of Customer Benefits of the Incentive
20 Compensation Plans

21 IV. CONCLUSION

22 **Q. Are you sponsoring any exhibits?**

23 A. Yes. I am sponsoring the following exhibits:

24 Exhibit A-71 (AMC-1) EICP Performance Measures;

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Exhibit A-72 (AMC-2)	Target Pay Level Market Analysis;
Exhibit A-73 (AMC-3)	Summary of Actual and Projected – Annual Incentive O&M Expenses; and
Exhibit A-74 (AMC-4)	Summary of Officer Compensation - Proxy Data.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

I. OVERVIEW

Q. What is the Company's compensation philosophy for non-officer employees?

A. Consumers Energy's compensation philosophy for its non-officer, non-union employees is to provide market-based compensation tied to performance. A competitive compensation policy benefits customers by attracting and retaining employees with the necessary skills and experience to deliver world-class customer service and minimize the risks and costs of employee turnover. Incentive pay is a component of providing market-based compensation.

Q. What is the Company's compensation philosophy for officer employees?

A. Consumers Energy's compensation philosophy for its officers is centered around four principles:

1. Align with increasing shareholder and customer value;
2. Enable the Company to compete for and secure top executive talent;
3. Reward measurable results; and
4. Be fair and competitive.

Incentive pay is a reasonable component of delivering this philosophy.

1 **Q. How does Consumers Energy structure non-officer compensation for its salaried**
2 **employees?**

3 A. Consumers Energy first determines what a competitive level of pay is for salaried
4 non-officer employees. It does so by using various market surveys. The practice of using
5 multiple surveys is common practice. It allows for a broader participant pool and
6 confirmation that the survey data is representative of market competitive wages and trends.
7 Consumers Energy then structures the compensation by allocating this market-based wage
8 between base salary and incentive compensation. The incentive compensation is part of
9 the overall total market-based competitive level and it is not in addition to it.

10 **Q. How does Consumers Energy structure officer compensation?**

11 A. Officer compensation levels are determined by the Compensation Committees of the
12 Boards of Directors of Consumers Energy and CMS Energy. The Company creates a
13 compensation package for officers that delivers base salary, annual incentive
14 compensation, and long-term incentive compensation targeted at the median or
15 50th percentile of the competitive market. In determining individual officer compensation
16 levels, the Compensation Committees are advised by an independent third-party consultant
17 and take into consideration market research, experience levels, and individual
18 contributions.

19 **Q. In this proceeding, is the Company requesting rate recovery of all Operating and**
20 **Maintenance (“O&M”) electric expenses related to short-term incentive**
21 **compensation plans?**

22 A. No. The Company utilizes both financial and non-financial (operational) goals in its
23 short-term incentive compensation plan. While the Company believes that both financial

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1 and non-financial (operating) short-term incentive compensation expenses are reasonable,
2 the Company in this case is excluding the costs of short-term incentive compensation
3 linked to financial goals (\$6.9 million). Included in that \$6.9 million amount is the removal
4 of the affordability (O&M savings) operational measure. The Company determined that
5 the affordability measure, although included among the Company's operational goals for
6 purposes of the EICP, is financial in nature; therefore, the Company removed the dollars
7 attributable to that measure from the rate request in this case along with the dollars
8 attributable to the other financial measures.

9 **Q. Is Consumers Energy requesting recovery of all officer incentive pay linked to**
10 **non-financial (operational) goals in this rate case proceeding?**

11 A. Yes. The Company is seeking recovery for the incentive costs associated with the
12 operational goals portion for all officers in this case. This is a result of 30% of officer pay
13 directly linked to operational measures.

14 **Q. Is Consumers Energy requesting recovery of long-term incentive pay in this rate case**
15 **proceeding?**

16 A. No. The Company is not seeking recovery for the costs of long-term incentive
17 compensation (sometimes referred to as restricted stock plans) in its rate recovery request
18 in this case.

19 **Q. Why is the Company requesting rate recovery of short-term incentive compensation**
20 **operational goal expenses?**

21 A. Consumers Energy uses market data to determine an overall competitive level of
22 compensation. Competitive compensation includes base salary and short-term incentive
23 compensation for officers and non-officers. Consumers Energy's overall compensation

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1 levels are reasonable compared to the market. Compensation levels without these incentive
2 payments would be below market competitive levels. Paying non-competitive levels of
3 compensation would result in a less qualified workforce that would not best serve
4 customers. A March 2025 ManpowerGroup report stated nearly three-quarters of
5 employers, 71%, still struggle to find skilled talent, according to ManpowerGroup's latest
6 Talent Shortage survey. This marks a jump from a decade ago, when only 40% of
7 employers reported such challenges. In order to hire and retain qualified personnel, it is
8 necessary to either pay a competitive incentive or increase base salaries to make up for the
9 missing incentive compensation component. Use of annual incentive mechanisms is a
10 recognized management technique for companies, including utility companies. As I
11 discuss later in my direct testimony, incentive pay is the number one compensation design
12 element used to influence short- to mid-term performance results. Incentive mechanisms
13 help communicate priorities, engage the employees in operating and financial success,
14 reward valued skills and behaviors, and create business understanding for employees.
15 Consumers Energy's incentive programs are structured in a way that is designed to help
16 keep non-officers and officers focused on operational performance areas such as
17 continuous improvement, safety, cost, reliability, and delivery. The incentive
18 compensation program encourages employees to deliver outcomes which result in meeting
19 customers' expectations. The EICP incentive compensation costs are reasonable costs of
20 doing business and, therefore, should be recovered in rates.

21 **Q. Who is eligible for the EICP incentives?**

22 A. All non-union employees are eligible for EICP incentives, with the exception of employees
23 who are rated as "under-performing" or "needs improvement" on their annual performance

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1 appraisals. These under-performing employees are ineligible to receive an EICP incentive.

2 Both non-officers and officers participate in an annual EICP incentive.

3 **Q. How are the EICP incentives structured?**

4 A. The EICP incentives are structured by non-officer and officer EICP. The 2024 non-officer
5 EICP equally weights the operational measures with the financial measures:

- 6 • Half (50.0%) of employees' incentive will be based on the achievement of one
7 operational performance measures. (For 2024 and 2025, there are six
8 operational measures.); and
- 9 • Half (50.0%) of employees' incentive will be based on the achievement of one
10 financial measure, Earnings Per Share ("EPS"). Consumers Energy is a vital
11 part of the Michigan economy, and it is important that the utility remains
12 financially strong so that it can provide the utility service that customers expect
13 and deserve; however, Consumers Energy is not seeking recovery of the
14 financial portion of the EICP.

15 The goals are the same for the officer EICP, but the weightings are different.
16 Officers are 30% based on the achievement of operational measures and 70% based on the
17 achievement of financial measures.

18 **II. EMPLOYEE COMPENSATION PHILOSOPHY**

19 **Q. What is Consumer Energy's philosophy about the overall level of compensation?**

20 A. The Company's management believes Consumers Energy should pay a fair and reasonable
21 salary, comparable to the market that is equitable to employees, consistent with Company
22 values and strategies, and that supports the highest level of customer service at a reasonable
23 cost.

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1 **Q. What are the components of Consumers Energy’s compensation for non-officer**
2 **employees?**

3 A. There are two parts of overall compensation for non-officer employees of Consumers
4 Energy. The first part is base pay or salary. The second part for salaried employees is
5 annual incentive compensation.

6 **Q. What are the components of Consumers Energy’s compensation for officers?**

7 A. There are three parts of overall compensation for officers of Consumers Energy. The first
8 two parts are cash compensation through base pay and annual incentive compensation. The
9 third part is equity-based long-term incentive. As I mentioned earlier in my direct
10 testimony, the Company is not seeking recovery for the costs of long-term incentive
11 compensation in its rate recovery request in this case.

12 **Q. Why does the Company make a portion of compensation subject to incentives?**

13 A. A wide body of research supports the view that incentive pay (a variable pay component)
14 works. One researcher states, “theory and research show that incentive pay can
15 substantially increase individual and organizational performance and can represent a
16 powerful tool for establishing a competitive advantage within an industry.” (Dow Scott,
17 *Incentive Pay: Creating a Competitive Advantage* – WorldatWork Press, 2007). There
18 are many more cases of incentive plans as an effective motivational tool. Group incentive
19 plans can contribute to organizational collaboration and achievement of company goals
20 which lead to benefits for customers. A May 15, 2018, Forbes article entitled “The Key
21 to an Effective Incentive Plan” (Bill Fotsch and John Case) continues to support this
22 theory indicating:

23 Incentive plans, by definition, are supposed to affect
24 people’s behavior on the job, day in and day out. They incent

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1 people to work harder and smarter, to go the extra mile, to
2 collaborate with their coworkers, to come up with new ideas
3 to improve some aspect of the business.

4 People don't work for money alone, but they do respond to incentives.

5 When properly selected and implemented, incentives motivate employees, focus
6 employees on a company's goals, and increase both individual work performance and team
7 performance. When goals are challenging yet achievable, employees are motivated to
8 increase productivity and performance to achieve the goal. In addition, incentives increase
9 a company's ability to attract, hire, and retain qualified and motivated individuals. A study
10 by the International Society of Performance Improvement showed that incentive pay
11 programs increase performance by an average of 22.0%. (International Society of
12 Performance Improvement, "Incentives Motivation and Workplace Performance Research
13 and Best Practices," Spring 2002). As stated by the Society of Human Resource
14 Management:

15 Research has demonstrated that some human resource
16 programs and initiatives produce a significant impact on
17 performance in organizations (as measured by factors such
18 as quality, productivity, speed, customer satisfaction and
19 unwanted turnover). The two initiatives that consistently
20 showed statistically significant positive results were linking
21 pay to performance and using variable pay. Research has
22 established the potential of variable pay to produce the
23 desired business results. [Robert Greene, "Variable Pay:
24 How to Manage it Effectively, Society of Human Resource
25 Management," April 2003.]

26 Consumers Energy has adopted incentives that are designed to emphasize
27 operational performance criteria in areas that are critical to the Company's utility business
28 and customers. Focusing employees on these goals provides both qualitative and
29 quantitative benefits for Consumers Energy's utility customers. High-level qualitative

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customer benefits are listed later in my testimony. Company witness Ashley E. Meschke's testimony illustrates the quantitative benefits to customers.

Q. Are the overall compensation levels for employees subject to the non-officer EICP reasonable?

A. Yes. Overall compensation levels for employees subject to the non-officer EICP and management's decision of how to allocate the overall compensation between base salary and EICP are reasonable. As stated later in my testimony, it is common practice for companies to have a variable pay (i.e. EICP) component of total competitive compensation levels.

Q. How does Consumers Energy determine what level of overall compensation for non-officers is reasonable?

A. First, Consumers Energy's management targets compensation to the market median. Second, Consumers Energy's management actively reviews compensation levels so that employees are neither overpaid nor underpaid relative to the market. Third, the Company uses a rigorous survey process which uses valid and reliable data from multiple third-party sources to determine median levels of compensation. Fourth, the Company reviews incentive compensation levels from third-party data sources to determine the target level of compensation. The fact that a portion of the compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. To the contrary, removing the incentive from employees' compensation package or failing to meet incentive performance goals, would render their compensation below-market.

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1 **Q. Would it be reasonable for Consumers Energy to pay employees below market level**
2 **on an ongoing basis?**

3 A. No.

4 **Q. Why would it be unreasonable for Consumers Energy to pay below market level?**

5 A. Consumers Energy has a responsibility to customers to employ a competent workforce that
6 is ready, willing, and best able to provide service for its customers. Paying competitive
7 wages and salaries is necessary to fulfill that commitment. It would not be reasonable or
8 fair to the Company, its employees, or customers for the MPSC to set rates at a level that
9 did not include reasonable levels of overall market-based compensation.

10 The level of service that customers deserve requires a qualified, experienced, and
11 motivated workforce. The Company can attract, retain, and motivate talented employees
12 when its overall compensation is competitive with market levels. A decision to compensate
13 employees below market levels would detract from the Company's ability to assemble the
14 committed and customer-focused workforce that customers deserve. Over time, this would
15 be detrimental to customers, as well as being unreasonable to the Company's diligent,
16 hardworking employees. Compensating employees below market levels will eventually
17 result in their leaving for jobs that are paying at market levels. Over time, the workforce
18 would tend to be less qualified, less experienced, less productive, and less capable of
19 serving customers (as the most capable would, in general, tend to go to employers paying
20 at competitive levels). This, in turn, could lead to less efficiency and could result in a need
21 to hire more employees to produce the same service to customers, thus increasing costs to
22 customers.

1 **Q. How does the Company determine the level of compensation for salaried non-officer**
2 **employees?**

3 A. For salaried non-officer employees, the Company uses salary survey data from utility and
4 energy companies. Using this survey data, a benchmarking analysis of base pay and
5 incentive pay is made between the Company's jobs and comparable survey jobs.
6 Benchmarking analysis is a comparison of jobs commonly found in the labor marketplace
7 and/or a job that is highly relevant/populated within a company. This comparison indicates
8 where the Company's pay stands relative to the market. The Company's goal is to target
9 base pay levels within plus or minus 5.0% of the market median for non-officers. While
10 pay for individuals inevitably varies from the survey market levels due to differences in
11 experience levels, education, job performance, longevity, position responsibilities, etc., the
12 survey data indicate that the Company's overall non-officer compensation levels, assuming
13 the EICP payment at the target level, are on average within target pay level of plus or minus
14 5.0% of market median. Exhibit A-72 (AMC-2) provides a summary of average exempt
15 and non-exempt base pay for Company benchmark jobs compared to market using 2024
16 data for 2025 pay structure purposes.

17 Paying compensation that approximates the market median is particularly
18 important given that Consumers Energy will continue to experience significant attrition
19 (current employees eligible for retirement is 19% of the workforce) and have a need over
20 the next few years to hire engineers, information technology, and other personnel to staff
21 various projects and serve customers. Competitive pay is necessary to retain the talent
22 needed to deliver on the Company's Integrated Resource Plan ("IRP"). In competing for
23 engineers, as well as other personnel that are skilled, high-performing customer-focused

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1 candidates, it will be important to have a reputation for paying a competitive level of overall
2 compensation. Excluding the incentive target amounts would result in the Company's pay
3 levels being as much as or greater than 10.0% below market level.

4 **Q. How do you know the market data that the Company is using are appropriate and**
5 **are not inflating salary levels?**

6 A. The Company uses several third-party survey sources to compare to the non-officer
7 salaried workforce. The Company participates in and uses an industry survey performed
8 by Willis Towers Watson, Aon Hewitt ("Aon"), and Mercer LLC ("Mercer"), which
9 are well-respected, independent third-party compensation experts. These surveys are
10 conducted by surveying companies which report data on an anonymous basis. When using
11 the survey data, the Company looks at the base pay and incentive reported for highly
12 populated jobs for which there is a comparable job match. In this way, the Company is
13 matching the relevant market, not trying to lead the market, and thus not inflating its overall
14 compensation above prevailing market levels. By using multiple independent survey
15 sources, the Company can determine if any one source is varying significantly from
16 another.

17 **Q. Can you give an example of the relationship between the Company's base pay levels**
18 **and the market's pay levels?**

19 A. See Exhibit A-72 (AMC-2) for a summary of average exempt and non-exempt base pay
20 for Company benchmark jobs.

21 **Q Does the Company attempt to keep salaries consistent with the rate of inflation?**

22 A. No. The Company's pay levels are designed to stay consistent with the costs of labor.
23 Labor costs and rate of inflation are not interchangeable. Cost of labor is what a particular

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geographic market offers as the “going rate” or compensation for its jobs. Inflation is a measure of the rate of rising prices of goods and services in an economy. Labor rates and inflation rates can change based on different factors or influences and at different rates. Labor rates follow what companies are doing to stay competitive, inflation follows economic trends which can be unrelated to how people are paid. Consumers Energy’s compensation is designed to be competitive with what is seen in the labor market including rewarding and motivating talent rather than trying to keep up with inflation. For rate making purpose, the Company follows the direction of the Commission’s December 22, 2021 Order in Case No. U-20963¹ and uses the same inflation factor to adjust both labor and non-labor expenses for determining projected labor costs.

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

¹ See pp. 244-251 for the discussion regarding inflation rates.

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1 98.0% of executives, 99.0% of management, 94.0% of non-sales professionals, and
2 86.0% of clerical and technicians were eligible for an annual incentive.

3 A 2012 Mercer study of more than 1,200 organizations reveals that actual company
4 spending on variable pay for salaried exempt employees, as a percentage of pay, is 12.0%
5 and salaried/hourly non-exempt employees, as a percentage of pay, is 6.0% to 7.0% for
6 energy companies. A 2009 Hewitt Associates study of more than 1,100 organizations
7 further reports that companies were budgeting variable pay for salaried exempt employees
8 at 11.8%, and 5.5% to 6.1% for salaried/hourly non-exempt employees, for 2010.
9 Ken Abosch, leader of Hewitt's North American Broad-Based Compensation Consulting
10 business, added:

11 Over the past decade, we've seen companies steadily shift
12 from a fixed pay model to one that emphasizes true
13 performance-based awards, and we expect this trend will
14 continue.

15 Consumers Energy's practice of making a portion of overall employee
16 compensation subject to incentives is consistent with best practices for compensation.

17 **Q. What has been the trend in variable or incentive pay?**

18 A. A 2016 study by Aon indicated a 72% growth in variable pay spend over the past 20 years.
19 Variable pay grew from 4.1% of base salaries in 1996 to 12.9% of base salaries in 2015.
20 Business incentive plans are the most prevalent with 77% of companies using this type of
21 variable pay award in 2015 up from 55% in 1996. Business incentive plans refer to plans
22 that are based on Company financial and/or operational goals. According to a 2021 study
23 published by WorldatWork and Compensation Advisory Partners, the vast majority of
24 companies (99%) have short-term incentive programs ("Incentive Pay Practices: Publicly
25 Traded Companies," July 2021, WorldatWork and Compensation Advisory Partners).

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Moreover, a 2020 study by Willis Towers Watson on Salary Increases shows that 89% of energy companies utilized short-term incentive (EICP) compensation programs.

Q. Why is the use of incentive pay such a widespread practice?

A. Incentive pay is the number one design used to influence short- to mid-term business or performance results. Coupled with clear strategy, solid leadership, and good, safe working conditions, variable pay incentive designs:

- Increase employees' understanding of what is important to the Company;
- Increase employees' identification with the Company's success and the factors by which it is measured;
- Reward valued skills and behaviors; and
- Enhance employee engagement by educating them on how and why their contributions will benefit them, the Company, and our customers.

Dividing overall compensation between base salary and incentive compensation is an approach that is common and effective in business today.

Q. How many employees does the Company have that will be eligible for the non-officer EICP payout?

A. Consumers Energy has approximately 4,500 employees (total utility) who are eligible to receive an incentive if, and when, the requirements for a payout are met. The risk of no payout is the same for all these eligible employees. Either every eligible employee receives a payout, or no one receives any incentive compensation.

Q. How did the Company determine the level of compensation that would be provided as incentive compensation for these eligible employees?

A. For the historical test year, the EICP target level for each pay grade was established by reviewing third-party market data on the mix of base salary and at-risk variable pay (EICP),

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historical rate case relief and amounts that will assist in motivating performance that will result in benefits to customers. The EICP compensation is part of the overall market-based competitive level of compensation, not in addition to it. Beginning in 2024, the EICP target levels are based on career stream and job level established by reviewing third-party market data on the mix of base salary and at-risk variable pay.

Q. Explain if the Company reduced base pay when it started to pay incentive awards in order to obtain market-based pay based on the combination of the two components of pay.

A. The Company has always had a broad-based incentive compensation plan in place for management level. In 2003, an EICP for employees in former 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 50th 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

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1 would need to offer \$52,000 to match the market's current pay. So, the alternative to
2 having an incentive component of overall compensation would be to raise base pay to the
3 market's overall compensation. Eliminating incentive pay would result in the same
4 compensation costs, but employees would lose focus on continuous improvement, safety,
5 quality, cost, reliability, and delivery to the customer. Increasing base pay would also
6 result in a higher level of fixed costs tied to base pay, such as certain pension and defined
7 contribution benefit plans, life insurance, disability insurance, and other salary-based
8 employee benefits.

9 The Company's overall compensation needs to be comparable to the market for
10 salaried employees regardless of whether it is composed of only base pay or composed of
11 base pay plus the target incentive award amount. The Company has maintained overall
12 compensation at competitive levels through base pay plus the target incentive award
13 amount.

14 **Q. Would elimination of incentive pay be in the best interests of customers?**

15 **A.** No. With incentive compensation, the employees and the Company must re-earn the at-risk
16 compensation each year. If high levels of performance are not met each year, incentive
17 pay can be reduced or eliminated. The elimination of variable "at risk" pay would create
18 a situation where all compensation is guaranteed and would remove an important incentive
19 to improve service. This result would be counter to customer interests. The elimination of
20 variable "at risk" pay would create a situation where compensation would be below market
21 competitive levels. Competitive pay is needed to attract and retain the high-quality talent
22 required to deliver exceptional service to customers. It would be difficult to achieve the
23 Company's purpose of world-class performance delivering hometown service without the

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1 right talent. The knowledge, skills, and abilities of Consumers Energy's employees are
2 key determinants in the quality and timeliness of service that customers receive. Our ability
3 to deliver what customers expect such as reliable and safe energy delivery, on-time
4 completion of service orders, and energy savings depends upon having the right talent in
5 the right job at the right time. Having incentive compensation that is structured around
6 goals that provide benefits to customers is in the best interest of the customer.

7 **Q. How does the Company determine the level of overall compensation for officers?**

8 A. A utility must maintain a competitive total compensation package to attract and retain
9 executive talent. As discussed above, Consumers Energy creates a compensation package
10 for officers that delivers base salary, annual incentives, and long-term incentives (excluded
11 from the Company's request in this rate case) targeted at the 50th percentile of the market,
12 as defined by a Compensation Peer Group approved by the Compensation Committees of
13 the Boards of Directors. The Compensation Peer Group consists of energy companies
14 comparable in business focus and size to CMS Energy with which the Company might
15 compete for executive talent. The Compensation Peer Group currently includes
16 19 companies.

17 **Q. How do you know the market data that you are using for officer compensation are**
18 **appropriate and are not inflating salary levels?**

19 A. Annually, the Compensation Committees engage an independent third-party consultant to
20 provide advice and information regarding compensation practices of a Compensation Peer
21 Group, which it develops based on criteria discussed below, as well as taking into account
22 additional information from published surveys of compensation in the public utility sector
23 and general industry. During the Compensation Committee's review of officers'

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1 compensation levels, consideration is given to the advice and information received from
2 the independent compensation consultant; however, the Compensation Committee is
3 ultimately responsible for determining the form and amount of the compensation programs.

4 Where available by position, Compensation Peer Group data serves as the primary
5 reference point for pay comparisons of utility specific roles, and broader survey data and
6 published proxy data are also provided by the compensation consultant as a point of
7 reference for utility-specific roles and comparisons of general industry roles. Where
8 available by position, the independent executive compensation consultant of the
9 Compensation Committee, gathers compensation data from Willis Towers Watson's
10 Energy Services Executive Database (over 50 investor-owned utilities) and Willis Towers
11 Watson's General Industry Executive Database (approximately 500 participating
12 companies), which it regresses based on CMS Energy's revenues to provide additional
13 market context to the Compensation Peer Group. In selecting members of the
14 Compensation Peer Group, financial and operational characteristics are considered. The
15 criteria for selection of the Compensation Peer Group included comparable revenue,
16 relevant utility industry group, similar business mix (revenue mix between regulated and
17 non-regulated operations), and availability of compensation and financial performance
18 data.

19 The survey data indicate that the Company's overall officer compensation levels,
20 assuming the EICP and restricted stock payment at the target market-based level, are
21 reasonable.

22 In addition, annually, proxy-advisor service companies Glass Lewis & Co. and
23 Institutional Shareholders Services assist institutional investors in their advisory vote on

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1 the reasonableness of compensation pay and practices of the proxy-named executive
2 officers by providing a vote recommendation. The incentive pay practices for the
3 proxy-named executive officers are the same as for the remaining officer group. In 2024,
4 both proxy advisory service firms recommended a vote “for” the proxy-named executive
5 officer compensation pay and practices. Also, shareholders voted 95% in favor to approve
6 executive compensation as described in the 2024 Proxy Statement which is above the S&P
7 500 average of 92%.

8 **Q. Is survey data information for the third-party consultant proprietary information?**

9 A. Yes. Consumers Energy’s Compensation Committees engages an independent third-party
10 consultant to provide information regarding officer compensation practices of the
11 Compensation Peer Group as well as additional information from Willis Towers Watson
12 published surveys of compensation in the public utility sector and general industry.

13 The Willis Towers Watson survey sources used by Pay Governance are produced
14 solely for use by database participants and are maintained by Willis Towers Watson in
15 connection with the participant’s own internal human resources management
16 department. The surveys are the confidential and proprietary work product of Willis
17 Towers Watson, which owns all related intellectual property rights. Pay Governance has
18 written consent from both Willis Towers Watson and CMS Energy to use the surveys on
19 CMS Energy's behalf. Pay Governance is prohibited from using or reproducing the
20 database and survey reports prepared by Willis Towers Watson.

1 **Q. Is the Company able to provide the survey data?**

2 A. No. The market median information the Company utilizes is confidential, proprietary, and
3 commercially sensitive data belonging to third parties. Consumers Energy is contractually
4 prohibited from sharing this information.

5 Although the Company is prohibited from sharing the market data used in setting
6 compensation for its top five officers, the Company recognizes that it could be helpful to
7 have access to some market data to evaluate the reasonableness of the compensation
8 included in rates for the Company's top five officers. Therefore, the Company compiled
9 and provided non-confidential market data using the following compensation elements
10 from the Compensation Peer Group's publicly filed proxy statements: salary, stock awards,
11 and non-equity incentive. See Exhibit A-74 (AMC-4).

12 Because this market data uses only publicly available non-proprietary information,
13 it does not perfectly represent the information that the Company used to benchmark and
14 assist the Compensation Committee to determine compensation for Consumers Energy's
15 top five officers. However, that does not support the conclusion that it is inadequate to
16 support the level of compensation for the Company's top five officers. First, the
17 proprietary benchmarking information alone does not mechanically decide how
18 compensation will be set. When making pay adjustments, the Compensation Committee
19 considers the CEO's recommendations, along with proprietary Compensation Peer Group
20 data, internal equity, tenure, and other proprietary market data from surveys provided by
21 the independent compensation consultant. Actual compensation decisions are based on the
22 following as described on page 21 through page 24 of my testimony. Second, the data
23 provided in Exhibit A-74 (AMC-4) is sufficiently consistent with the proprietary data that

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1 it does allow for a valid comparison of the compensation of the highest paid through the
2 2nd, 3rd, 4th, and 5th highest paid named officers compared to the Company's compensation
3 peer group.

4 **Q. Does the independent consultant provide other services for CMS Energy or**
5 **Consumers Energy that could result in a conflict of interest?**

6 A. No. The independent consultant is required to obtain approval of the Compensation
7 Committee of the Boards of Directors before undertaking any activity on behalf of the
8 management of CMS Energy or Consumers Energy. During the time the consultant has
9 been engaged as the compensation consultant for the Boards of Directors, it has not
10 performed any services on behalf of the management of CMS Energy or Consumers
11 Energy. The independent consultant is hired by and serves the Compensation Committee;
12 it is not hired by or providing services to CMS Energy or Consumers Energy.

13 **Q. Are surveys the only determining measure used in setting officer compensation**
14 **levels?**

15 A. No. Additionally, the Compensation Committee considers experience levels and
16 individual contributions of the respective officers.

17 **Q. Are incentive plans for officers common in the utility industry or in other industries?**

18 A. Yes, incentive plans are prevalent. Research from Mercer, U.S. Compensation Planning
19 2014/2015 survey indicates that approximately 96.0% of companies, and 98.0% of energy
20 companies, offer annual incentive (variable pay) programs for officers. The survey data
21 support the conclusions that including incentive pay as part of a competitive pay package
22 is a standard practice and is required to attract and retain qualified officers.

1 **III. INCENTIVE COMPENSATION PLANS**

2 **A. Description of Incentive Plans**

3 **Q. Please describe the EICP that is in place for 2024.**

4 A. The EICP for 2024 is based on achieving performance goals related to critical areas of the
5 Company's operations. The goals focus on continuous improvement measures and
6 maintaining financial health to deliver value benefits to customers (not seeking recovery
7 of financial goals in this case). The Company's EICP goals seek to encourage employees
8 to provide reliable energy, customer value, and responsive service to customers, and to do
9 so safely. Each year, the Company establishes utility-specific performance criteria which
10 focus on continuous improvement goals and breakthrough goals. For 2024, there were six
11 specific operational performance measures, and one measure related to being financially
12 healthy. The EICP Operational Performance Measures are summarized on Exhibit A-71
13 (AMC-1). The 2024 officer and non-officer goals and weighting are shown on page 1 and
14 operational goal targets on page 2.

15 **Q. Please describe Exhibit A-71 (AMC-1).**

16 A. Exhibit A-71 (AMC-1) identifies the operational performance areas that the EICP focuses
17 on and identifies the specific measures that have been adopted for each of these areas. For
18 the 2024 historical year, 50.0% of the non-officer incentive compensation and 30% of
19 officer incentive compensation was based on operational performance. For purposes of
20 this rate case, the Affordability (O&M savings from Waste Elimination) measure
21 associated cost has been removed from the rate request as the Company has determined
22 that it is financial in nature.

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1 **Q. Is the structure of the EICP goals for 2025 similar to 2024?**

2 A. The specific performance measures and targets for 2025 are, as in prior years, a
3 combination of measures related to operational performance and financial performance.
4 As indicated above, the Company is not seeking recovery of the financial performance
5 measures in the case. For non-officers, the operational performance and financial health
6 goals will be weighted equally (50% operational and 50% financial). For officers, the
7 operational performance and financial performance measures are weighted 30%
8 operational and 70% financial. The officer operational goals are the same as the
9 non-officer operational goals.

10 **Q. Will the non-officer performance measures continue to incorporate measures that**
11 **provide benefits to Consumers Energy's customers?**

12 A. Yes. Performance measures will continue the focus on world class performance delivering
13 hometown service and will continue to have as their foundation continuous improvement
14 and breakthrough measures. While the number and precise phrasing of operational goals
15 may vary from the historical test year, areas of focus will continue to include safety,
16 reliability, cost, delivery, and customer care.

17 **Q. Will the officer performance measures continue to incorporate measures that provide**
18 **benefits to Consumers Energy's customers?**

19 A. Yes. Operational and financial performance measures will continue the focus on world
20 class performance delivering hometown service and will continue to have as their
21 foundation continuous improvement and breakthrough measures. The operational
22 measures will hold a weighting of 30%, meaning 30% of the officer incentive
23 compensation is based on operational performance (same goals as non-officers) and the

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1 remaining 70% is based on financial performance. As noted above, the Company is not
2 seeking recovery of the financial performance measure in this case.

3 **Q. Please discuss the strategy and process for developing the EICP goals.**

4 A. Company witness Meschke provides a discussion of the strategy and process for
5 developing the EICP goals.

6 **Q. Why has the Company's management chosen to design the EICP with broad goals
7 and objectives on a Company-wide basis rather than individual goals and objectives
8 for individual employees?**

9 A. It is necessary and appropriate for a large organization, such as Consumers Energy, to
10 establish broad goals and objectives that are communicated to all employees as matters that
11 are important to the success of the organization. Some employees will be in a better
12 position to influence whether particular goals and objectives are met, but having every
13 employee linked to a set of common customer-focused objectives is an effective method
14 for emphasizing the importance of customer value and service. Having common goals and
15 objectives (i) provides clear communication of Company goals, (ii) encourages employees
16 to support each other and work together for common goals, and (iii) provides a scorecard
17 with a focus on corporate-wide goals that benefit customers.

18 Consumers Energy incorporates individual goals through the annual performance
19 feedback process, which includes the creation and review of individual goals and objectives
20 for each salaried employee and the opportunity to recognize and reward individual
21 performance. The existence of a common set of customer objectives enables supervisors
22 and employees to establish individual goals and objectives which are supportive of, and in
23 alignment with, the corporate goals reflected in the EICP.

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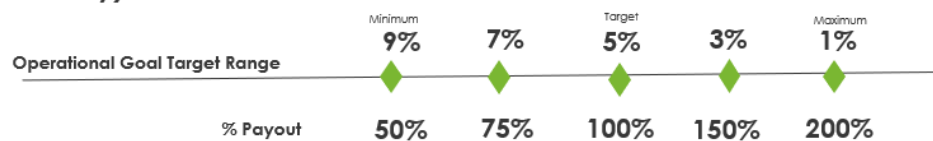
1 **Q. How are the payout levels that are shown on Exhibit A-71 (AMC-1) set?**

2 A. When setting payout levels, threshold is set at a level of achievement that can typically be
3 reached 80% to 90% of the time in a 10-year period. Maximum payout is for exceptional
4 performance (10% to 20% of the time in a 10-year period). These levels are to engage the
5 employees in meeting the goals. Employees must re-earn the incentive at-risk portion of
6 compensation each year. If the threshold to achieve a payout were set at a level viewed as
7 not achievable, it would be difficult to maintain employee motivation and would result in
8 fewer customer benefits. Overall compensation levels, including the EICP at target (100%)
9 level that Consumers Energy seeks, are not excessive. It is reasonable for Consumers
10 Energy to pay its employees competitive levels of compensation.

11 **Q. Are the payout levels that are shown on Exhibit A-71 (AMC-1) similar to 2024 and**
12 **the projected test year?**

13 A. Yes, each operational measure will have its own threshold, target, and maximum for
14 payout. This practice aligns better with market practice and with engaging and motivating
15 performance. Gallup research supports substantial and well-established connections
16 between employee engagement and the achievement of outcomes critical to the business
17 and to customers. See illustration of banded goals below:

Example (Illustration Only):



18 This structure was in place for 2024 and planned to be in place for the projected test year.

1 **Q. Why are you including both gas and electric performance measures in this plan as**
2 **this is an electric rate case?**

3 A. For purposes of efficiency and improved service, the Company has combined operations
4 as one organization. For that reason, the plan contains both gas and electric measures.

5 **Q. How are the targets for the annual officer EICP incentives measures determined?**

6 A. As mentioned earlier, the goals are the same for the officer and non-officer EICPs, but the
7 weightings are different.

8 **Q. Why is the weighting different for the officer plan?**

9 A. Officer annual incentive awards were based on the achievement of EPS and utility
10 operational goals for the historical test year. As indicated above, the officer plan has a 30%
11 weighting of the same operational goals as non-officers. This strengthens the linkage of
12 officer and non-officer performance while aligning with typical indicators of officer
13 strategy execution through financial goals (weighted at 70%) and corresponding higher
14 weighting.

15 **Q. How are the target amounts for the annual officer incentives determined?**

16 A. The Compensation Committee determines the target amounts of the annual officer
17 incentives. In determining the amount of target incentives, the Compensation Committee
18 considers the following factors:

- 19 • The target incentive level and actual incentives paid in recent years;
- 20 • The relative importance, in any given year, of each performance goal
- 21 established; and
- 22 • The advice of the Compensation Committee's compensation consultant as to
- 23 compensation practices at other companies in the Compensation Peer Group
- 24 and the utility industry.

B. Assessment of Customer Benefits of the Incentive Compensation Plans

Q. What level of expenses for Consumers Energy's incentive plans has been included in the test year revenue requirement?

A. The Company is requesting recovery of electric 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-72 (AMC-2) for which the Company is requesting recovery:

- **Employee Safety** (OSHA Recordable)
(Incidents, High Risk Injuries and Zero fatalities)
- **Culture Index**
(Employee Empowerment, Employee Engagement and DEI)
- **Customer Experience - Cxi**
(Survey measuring Customer Experience)
- **Electric Reliability - SAIDI**
(System Average Interruption Duration Index)
- **Methane Emission Reduction**
(Reduction of Methane Emissions through replacements of Mains and Services, etc.)

The level of expense is approximately \$2.2 million as illustrated in Exhibit A-73 (AMC-3).

Q. Please explain Exhibit A-73 (AMC-3), page 2.

A. Exhibit A-73 (AMC-3), page 2, presents the amounts of the projected O&M expenses that were developed by applying either an inflation rate or a merit increase rate to historical O&M expense. Page 2, column (b), shows the historical O&M expense. Column (c) shows the historical amount that an inflation or labor rate was applied to. Columns (e) and (g) show the amounts to which an inflation rate or labor increase rate were applied for each bridge period, respectively. Columns (d), (f), and (h) show the labor and inflation increases for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b),

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(d), (f), (h), and (i). For purposes of incentive expense, only labor increase is applicable.
No inflation rate was applied.

Q. How are the electric expenses of \$2.2 million related to annual incentive compensation calculated?

A. The \$2.2 million for EICP incentive compensation is based on the following:

- For officers: The rate case expense amount is based on 2024 salaries multiplied by the approved target incentive percentage of salary from the 2024 Compensation & Human Resources Committee of the Board of Directors. Factors that impact the incentive expense year-over-year are retirements of officers and successors being at lower incentive amounts (decrease expense), forecasted salary increases (increase expense), and addition of new officers (increase expense) as indicated below.
- For non-officers: The rate case expense amount is based on an estimate of the number of employees in each career stream and job level multiplied by the plan prescribed incentive target amount. Progression to higher job levels as employees gain additional work experience will increase the amount of incentive expense year-over-year and headcount reductions will decrease the amount of incentive expense year-over-year.

Q. How was the electric portion of the incentive compensation expense determined?

A. The allocation percentages were supplied by the Accounting department.

Q. Is a portion of the electric 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.

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Q. Do Consumers Energy's electric 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:

	EICP		Long-term incentive	
			EICP	
Reasonable Compensation Level	Base Salary		Base Salary	
Market-based Compensation Level	Company Non Officer Compensation Level		Company Officer Compensation Level	

1 **Q. What is the appropriate standard from a business perspective in evaluating the**
2 **reasonableness of the EICP costs?**

3 A. Making a portion of compensation subject to incentives is a recognized, well-established,
4 common practice in the utility industry and is reasonable and appropriate. The appropriate
5 standard from a business perspective in evaluating whether the level of compensation is
6 reasonable is whether the overall level of compensation, including both base salary and
7 incentive compensation, is reasonable. Using this standard would also be appropriate for
8 ratemaking purposes. Looking at whether the overall level of compensation is reasonable
9 will provide a better indication of whether the incentive plan results in excess rates than
10 attempting to examine the cost allocable to the incentive compensation compared to
11 benefits to customers. The overall level of compensation that Consumers Energy has
12 included in its request in this case is reasonable.

13 **Q. Under the Company's proposal, do shareholders bear a portion of the EICP costs?**

14 A. Yes. The Company's incentive compensation proposal in this case does result in
15 shareholders bearing a portion of incentive costs. The Company's proposal to include
16 incentive compensation costs at target levels will result in the Company absorbing the
17 incentive compensation costs in those years when the actual payouts are greater than target
18 level and for the financial performance measures' cost. Thus, shareholders will absorb any
19 resulting increase in costs arising from above-target performance and for financial
20 measures. If actual payouts in future years are less than target levels due to under
21 performance, then the Company's shareholders will absorb the consequence of
22 underperformance results along with customers. The Company is allocating to

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shareholders 100% of the costs of incentive compensation for above-target performance and financial measures.

Q. Is the payment of incentive compensation reasonable given the economic conditions facing the Company's customers?

A. Yes. The incentive compensation costs are reasonable costs of doing business. The market median of survey data reflects current economic conditions and current pay practices. The Company maintains an annual practice of surveying the external market. Any trends in compensation – increases/decreases – would be reflected in the market survey results. Paying a reasonable level of compensation is in the best interests of the Company's customers. Incentive compensation does not result in excessive compensation and is reasonably necessary to attract, retain, and motivate a talented workforce to serve customers. Further, gaps between the skills that employers require and those available in the labor market are growing. Paying a reasonable level of compensation which includes incentive compensation is necessary to attract, retain, and motivate a talented workforce. As of December 2024, the unemployment rate was 5.0% in Michigan and 4.1% nationally, according to the Bureau of Labor Statistics ("BLS"). In addition, BLS data show that there are more job openings in the United States than there are unemployed people. The war for talent is real, and the Company must offer a compelling value proposition to attract and retain the talent required to realize our Company purpose of world-class performance delivering hometown service.

Q. Is the EICP a bonus or profit-sharing plan?

A. No. The EICP is not a bonus or profit-sharing plan. A bonus is a discretionary payment given without predetermined goals or objectives and a profit-sharing plan entitles

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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

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goals are not achieved, cash compensation is reduced or eliminated. Variable pay creates a performance culture rather than an entitlement culture.

In addition, an incentive program structured to focus employee attention on operational performance results in both qualitative and quantitative customer benefits. Among other things, customers benefit from increased cyber security, reliability, and on-time delivery and the focus on employee and public safety that helps reduce potential increased costs.

A quantitative analysis of the benefits received by the customer as a result of the EICP is discussed by Company witness Meschke in her direct testimony in this case.

Q. Has Consumers Energy assessed whether benefits to customers of this program equal or exceed costs?

A. Yes. The performance measures provide appreciable benefits to customers. The costs of the EICP are projected at approximately \$2.2 million for the test year. The quantifiable electric benefits illustrated in Company witness Meschke's direct testimony are \$3.6 million, which shows that the benefits to customers of the Company's EICP Program outweigh the costs of the program. Since this amount is part of the overall level of reasonable compensation, rather than being in addition to it, all benefits to customers are achieved at zero additional cost to customers. Achievement of the Company's EICP goals and objectives result in pay that is competitive with the labor market, not above the market. The EICP costs are not in addition to the reasonable level of compensation, they are part of the reasonable level of market-based compensation. If these amounts are not paid, then overall compensation would be at a level which is below the market level. There is no valid basis to eliminate incentive costs from the cost of service recovered in rates because

1 they are a part of an incentive plan rather than including these costs as part of base pay. As
2 stated before, overall levels of compensation are at levels that are not excessive. Rate
3 recovery of 100.0% should be allowed.

4 **IV. CONCLUSION**

5 **Q. Is the Company's overall compensation program, including the customer-focused**
6 **incentive, reasonable?**

7 A. Yes. The approach used by the Company is a reasonable approach, is consistent with
8 industry standards, and represents well-established best practices for creating customer
9 focus through compensation design, and it does so without any additional customer cost
10 above the market. The overall compensation levels are reasonable relative to the market,
11 are determined in a reasonable manner, and are a reasonable cost of doing business.
12 Compensation is structured in a manner that rewards improved operational and financial
13 performance that benefits customers. The incentive compensation costs should, therefore,
14 be included in the cost of service recovered from customers. These are legitimate and
15 reasonable costs of doing business. Rates established in this rate case should include
16 approximately \$2.2 million for incentive compensation expense.

17 **Q. Please summarize reasons why full recovery of incentive compensation costs should**
18 **be allowed in this case.**

19 A. Reasons that full recovery of operational goal incentive compensation costs should be
20 allowed include the following:

- 21 • Employee compensation is a reasonable cost of doing business, has been set at
22 a reasonable level, and has been determined using a reasonable methodology;
- 23 • The amount of compensation that is subject to incentive measurements is part
24 of the market-based compensation level, not in addition to it;

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- 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 generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

REDACTED
DIRECT TESTIMONY
OF
PATRICK D. DALY
ON BEHALF OF
CONSUMERS ENERGY COMPANY

June 2025

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1 **Q. Please state your name and business address.**

2 A. My name is Patrick D. Daly, and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
6 as Director of Revenue Requirements.

7 **Q. Please describe your educational background.**

8 A. I received a Bachelor of Arts degree in Economics & Management from Albion College in
9 2007 and Master of Science in Accountancy degree from Western Michigan University’s
10 Haworth College of Business in 2008. I am also a Certified Public Accountant licensed in
11 the state of Michigan.

12 **Q. Please describe your professional experience.**

13 A. From 2008 to 2017, I practiced public accounting with the accounting firm PwC with a
14 focus on performing financial statement and internal control audits for companies within
15 the power and utility industry. I progressed through several levels of increasing
16 responsibility during this time, achieving the position of Senior Manager in July 2017. In
17 2018, I transferred to PwC’s management consulting practice again with a focus in the
18 power and utility industry.

19 In April 2019, I joined DTE Energy as a Principal Financial Analyst in the
20 Accounting Policy & Research organization. My responsibilities included, among other
21 things, determining the appropriate accounting for major transactions, and the
22 implementation of new accounting standards. In April 2022, I accepted a position in DTE’s
23 Regulatory Accounting & Strategy organization. My responsibilities included assisting

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1 with the development and management of regulatory accounting policies and practices as
2 well as supporting regulatory filings. I also had responsibility for analyzing the accounting
3 implications of new legislation and Michigan Public Service Commission (“Commission”
4 or “MPSC”) orders and supporting expert testimony on accounting issues and financial
5 projections in various proceedings before the MPSC. I joined Consumers Energy as
6 Director of Revenue Requirements in July 2024.

7 **Q. What are your responsibilities as the Director of Revenue Requirements at**
8 **Consumers Energy?**

9 A. As the Director of Revenue Requirements, I am responsible for managing and preparing
10 the following: (i) studies related to the level of the Company’s revenue requirements,
11 including the preparation, coordination, and monitoring of electric and gas general rate
12 case filings before the Commission; and (ii) other financial analyses.

13 **Q. Have you previously filed testimony with the MPSC?**

14 A. Yes. I filed testimony in the following case:

15 Case No. U-21338 DTE Electric Company 2023 Securitization

16 **Q. What is the purpose of your direct testimony in this proceeding?**

17 A. In my direct testimony, I will cover the following topics: (i) the Company’s revenue
18 deficiency calculation for the historical year; (ii) the Company’s revenue deficiency
19 calculation for the projected test year; (iii) requests related to distribution capital deferrals;
20 and (iv) the projected test year revenue requirement for the Demand Response (“DR”)
21 Programs. In addition, I will request regulatory asset treatment for the Company’s proposed
22 ramp-up to its Low Voltage Distribution (“LVD”) Forestry program expenditures as
23 supported by Company witness Sara E. Stewart. Finally, I describe the amounts included
24 for recovery in this case related to the SAP S/4HANA Implementation Project (“SAP

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S/4HANA Project”) and request the deferral of related operating and maintenance (“O&M”) expense and an adjustment to the amortization period of the cloud implementation costs for the software as a service (“SaaS”) solutions associated with the project.

Q. How is your direct testimony organized?

A. My direct testimony is organized in sections consistent with the topics I will be covering:

SECTION I: HISTORICAL YEAR

SECTION II: PROJECTED TEST YEAR

SECTION III: REGULATORY ASSETS AND OTHER ACCOUNTING TREATMENT

SECTION IV: DISTRIBUTION DEFERRAL

SECTION V: DEMAND RESPONSE

Q. How does the Company present the historical and projected revenue deficiency calculations?

A. The Company presents the historical and projected revenue deficiency calculations in compliance with the Commission’s Standard Filing Requirements that were approved in Case No. U-18238.

Q. Please describe the revenue requirements determination.

A. My direct testimony presents the revenue deficiency for the actual historical period. Additionally, my direct testimony presents and explains how the revenue deficiency for the future projected test year was developed. I will also reconcile the historical and projected test year periods. Through this filing, the Company demonstrates that it requires a rate increase to earn a just and reasonable return.

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1 **Q. Are you sponsoring any exhibits in this proceeding?**

2 A. Yes. The historical test year exhibits are identified in Section I of my direct testimony.
3 The projected test year exhibits are identified in Section II of my direct testimony. In
4 addition, I am sponsoring the following exhibits:

5 Exhibit A-82 (PDD-58) LVD Forestry Ramp-up – Revenue
6 Deficiency Impact of O&M Deferral;

7 Exhibit A-83 (PDD-59) Demand Response Revenue
8 Requirement;

9 Exhibit A-84 (PDD-60) Distribution Deferral for the
10 projected test year ending February
11 28, 2025;

12 Exhibit A-85 (PDD-61) Distribution Deferral for the
13 projected test year ending February
14 28, 2026; and

15 **Confidential** Exhibit A-86 (PDD-62) SAP S/4HANA Implementation
16 Project – Revenue Deficiency Impact
17 of O&M Deferral.

18 **Q. Were the exhibits presented in your direct testimony prepared by you or under your**
19 **direction and supervision?**

20 A. Yes.

21 **I. HISTORICAL YEAR**

22 **Q. What is the actual historical year used in the exhibits and supporting testimony?**

23 A. The Company selected the 2024 calendar year as the historical year.

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Q. Please identify the exhibits that you are sponsoring associated with the historical year.

A. The following exhibits are being submitted to satisfy the historical test year requirements:

Exhibit A-1 (PDD-1)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Historical Year Ended December 31, 2024;

Exhibit A-1 (PDD-2)	Schedule A-2	Historical Financial Metrics – Electric Results Only;

Exhibit A-2 (PDD-3)	Schedule B-1	Rate Base for the Historical Year Ended December 31, 2024;

Exhibit A-2 (PDD-4)	Schedule B-2	Total Utility Plant for the Historical Year Ended December 31, 2024;

Exhibit A-2 (PDD-5)	Schedule B-3	Depreciation Reserve and Other Deductions for the Historical Year Ended December 31, 2024;

Exhibit A-2 (PDD-6)	Schedule B-4	Working Capital for the Historical Year Ended December 31, 2024;

Exhibit A-2 (PDD-7)	Schedule B-5	13-Month Average Balance Sheet for the Historical Year Ended December 31, 2024;

Exhibit A-2 (PDD-8)	Schedule B-6	Point-In-Time Balance Sheet for the Historical Year Ended December 31, 2024;

Exhibit A-3 (PDD-9)	Schedule C-1	Adjusted Net Operating Income for the Historical Year Ended December 31, 2024;

Exhibit A-3 (PDD-10)	Schedule C-2	Calculation of the Revenue Conversion Factor for the Historical Year Ended December 31, 2024;

Exhibit A-3 (PDD-11)	Schedule C-3	Operating Revenue for the Historical Year Ended December 31, 2024;

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1	Exhibit A-3 (PDD-12)	Schedule C-4	Cost of Fuel and Purchased Power
2			for the Historical Year Ended
3			December 31, 2024;
4	Exhibit A-3 (PDD-13)	Schedule C-5	Operation and Maintenance
5			Expenses for the Historical Year
6			Ended December 31, 2024;
7	Exhibit A-3 (PDD-14)	Schedule C-5.1	Operation and Maintenance
8			Expenses by Witness for the
9			Historical Year Ended
10			December 31, 2024;
11	Exhibit A-3 (PDD-15)	Schedule C-6	Depreciation and Amortization
12			Expenses for the Historical Year
13			Ended December 31, 2024;
14	Exhibit A-3 (PDD-16)	Schedule C-7	General Taxes for the Historical
15			Year Ended December 31, 2024;
16	Exhibit A-3 (PDD-17)	Schedule C-8	Federal Income Taxes for the
17			Historical Year Ended December 31,
18			2024;
19	Exhibit A-3 (PDD-18)	Schedule C-9	State Income Taxes for the Historical
20			Year Ended December 31, 2024;
21	Exhibit A-3 (PDD-19)	Schedule C-10	Other (or Local) Taxes for the
22			Historical Year Ended December 31,
23			2024;
24	Exhibit A-3 (PDD-20)	Schedule C-11	Allowance for Funds Used During
25			Construction for the Historical Year
26			Ended December 31, 2024;
27	Exhibit A-3 (PDD-21)	Schedule C-12	Income Tax Effect of Interest for the
28			Historical Year Ended December 31,
29			2024;
30	Exhibit A-3 (PDD-22)	Schedule C-13	Interest Synchronization Adjustment
31			for the Historical Year Ended
32			December 31, 2024;
33	Exhibit A-4 (PDD-23)	Schedule D-1	Capital Structure and Rate of Return
34			Summary for the Historical Year
35			Ended December 31, 2024;

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Exhibit A-4 (PDD-24) Schedule D-2 Cost of Long-Term Debt (Excluding Securitization) for the Historical Year Ended December 31, 2024;

Exhibit A-4 (PDD-25) Schedule D-3 Cost of Short-Term Debt for the Historical Year Ended December 31, 2024;

Exhibit A-4 (PDD-26) Schedule D-4 Cost of Preferred Stock for the Historical Year Ended December 31, 2024; and

Exhibit A-4 (PDD-27) Schedule D-5 Cost of Common Shareholder's Equity for the Historical Year Ended December 31, 2024.

Q. Please discuss the organization and format of the historical period exhibits.

A. The organization and format of the historical period exhibits are specified by the MPSC's filing requirements. 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). Most of the exhibits include the presentation of both a "total electric amount" and a "jurisdictional electric amount." The total electric amounts were converted to jurisdictional electric amounts using the factors from the Commission Order in Electric Rate Case No. U-21389 as they were the factors in effect at the end of the historical test year.

Q. Who is sponsoring the historical year Schedule E exhibits?

A. The historical year Schedule E exhibits are sponsored by Company witness Eugene M. Breuring.

Q. Please describe the Schedule A exhibits for the historical period.

A. Exhibit A-1 (PDD-1), Schedule A-1, is the computation of the electric revenue deficiency for the year ended December 31, 2024. Exhibit A-1 (PDD-2), Schedule A-2, is a multiple page exhibit that provides financial metrics on both a financial basis (pages 1 through 3)

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and a ratemaking basis (pages 4 through 6) for the years 2020 through 2024. Pages 1 and 4 calculate an electric earned rate of return on common equity for each of these years. The \$2.0 million jurisdictional electric revenue deficiency is shown on Exhibit A-1 (PDD-1), Schedule A-1, line 8. Schedule A-1 is developed from financial data presented in Schedules B, C, and D described below.

Q. Please describe the Schedule B exhibits for the historical period.

A. Exhibit A-2 (PDD-3), Schedule B-1, presents the calculation of average electric rate base for the year ended December 31, 2024 in the jurisdictional electric amount of \$14.2 billion as shown on line 7, which is carried forward to Exhibit A-1 (PDD-1), Schedule A-1, line 1. Exhibit A-2 (PDD-4), Schedule B-2, through Exhibit A-2 (PDD-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 period.

A. Exhibit A-3 (PDD-9), Schedule C-1, presents the calculation of adjusted NOI for the year ended December 31, 2024 in the jurisdictional amount of \$833.6 million, as shown on line 33, which is carried forward to Exhibit A-1 (PDD-1), Schedule A-1, line 2. Exhibit A-3 (PDD-10), Schedule C-2, through Exhibit A-3 (PDD-22), Schedule C-13, support the development of the various components of adjusted NOI. The Schedule C data for the historical period is generally sourced to the Company's 2024 Form P-521 Annual Report to the MPSC.

Q. Please describe the Schedule D exhibits for the historical period.

A. Exhibit A-4 (PDD-23), Schedule D-1, presents the overall rate of return summary for the year ended December 31, 2024. The weighted cost of capital of 5.86% is shown on line 14,

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column (h), and is carried forward to Exhibit A-1 (PDD-1), Schedule A-1, line 4. Exhibit A-4 (PDD-24), Schedule D-2, through Exhibit A-4 (PDD-27), Schedule D-5, support the development of various components of the overall rate of return for the historical period including: (i) debt; (ii) preferred stock; (iii) common equity; and (iv) other sources of financing.

Q. Based on your review of the historical year exhibits, was there a revenue deficiency in the historical year?

A. Yes. I have calculated a historical year jurisdictional electric revenue deficiency for the 12-month period ended December 31, 2024, which is presented on Exhibit A-1 (PDD-1), Schedule A-1, as follows:

<i>Jurisdictional</i>	<i>(\$ In Thousands)</i>
Rate Base	\$14,241,328
Adjusted NOI	\$ 833,578
Overall Rate of Return	5.85%
Required Rate of Return	<u>5.86%</u>
Income Required	\$ 835,097
Income Deficiency (Sufficiency)	1,519
Revenue Multiplier	<u>1.3381</u>
Revenue Deficiency (Sufficiency)	\$ <u>2,033</u>

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, then ratemaking adjustments and normalizations are recognized, where appropriate, as summarized on Exhibit A-3 (PDD-9), Schedule C-1. I will describe the adjustments and

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normalizations in the second part of my direct testimony, which covers the projected test year.

II. PROJECTED TEST YEAR

Q. What projected test year has the Company used in this case?

A. The Company selected the 12 months ending April 30, 2027 as the projected test year in this proceeding.

Q. Please identify the exhibits that you are sponsoring to comply with the Commission's filing requirements related to the projected test year.

A. The following exhibits are being submitted to support and satisfy the projected test year Filing Requirements:

Exhibit A-11 (PDD-28)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-11 (PDD-29)	Schedule A-2	Financial Metrics – Ratemaking Basis – For the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-11 (PDD-30)	Schedule A-3	Comparison of the Historical and Projected Revenue Requirement for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-12 (PDD-31)	Schedule B-1	Rate Base for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-12 (PDD-32)	Schedule B-2	Total Utility Plant for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-12 (PDD-33)	Schedule B-3	Depreciation Reserve and Other Deductions for the Projected 12-Month Period Ending April 30, 2027;

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1	Exhibit A-12 (PDD-34)	Schedule B-4	Working Capital Summary for the
2			Projected 12-Month Period Ending
3			April 30, 2027;
4	Exhibit A-12 (PDD-35)	Schedule B-5	Capital Expenditures Summary for
5			the Projected 12-Month Period
6			Ending April 30, 2027;
7	Exhibit A-13 (PDD-36)	Schedule C-1	Adjusted Net Operating Income for
8			the Projected 12-Month Period
9			Ending April 30, 2027;
10	Exhibit A-13 (PDD-37)	Schedule C-1.1	Development of Adjusted Net
11			Operating Income for the Projected
12			12-Month Period Ending
13			April 30, 2027;
14	Exhibit A-13 (PDD-38)	Schedule C-2	Calculation of the Revenue
15			Conversion Factor for the Projected
16			12-Month Period Ending April 30,
17			2027;
18	Exhibit A-13 (PDD-39)	Schedule C-3	Operating Revenues for the
19			Projected 12-Month Period Ending
20			April 30, 2027;
21	Exhibit A-13 (PDD-40)	Schedule C-4	Cost of Fuel and Purchased Power
22			for the Projected 12-Month Period
23			Ending April 30, 2027;
24	Exhibit A-13 (PDD-41)	Schedule C-5	Operating and Maintenance
25			Expenses for the Projected 12-Month
26			Period Ending April 30, 2027;
27	Exhibit A-13 (PDD-42)	Schedule C-5.1	Summary of Inflation and Merit
28			Increases Included in Operation and
29			Maintenance Expenses for the
30			Projected 12-Month Period Ending
31			April 30, 2027;
32	Exhibit A-13 (PDD-43)	Schedule C-6	Depreciation and Amortization
33			Expenses for the Projected 12-Month
34			Period Ending April 30, 2027;

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1	Exhibit A-13 (PDD-44)	Schedule C-7	General Taxes for the Projected
2			12-Month Period Ending April 30,
3			2027;
4	Exhibit A-13 (PDD-45)	Schedule C-8	Federal Income Taxes for the
5			Projected 12-Month Period Ending
6			April 30, 2027;
7	Exhibit A-13 (PDD-46)	Schedule C-9	State Income Taxes for the Projected
8			12-Month Period Ending April 30,
9			2027;
10	Exhibit A-13 (PDD-47)	Schedule C-10	Other (or Local) Taxes for the
11			Projected 12-Month Period Ending
12			April 30, 2027;
13	Exhibit A-13 (PDD-48)	Schedule C-11	Allowance for Funds Used During
14			Construction for the Projected
15			12-Month Period Ending April 30,
16			2027;
17	Exhibit A-13 (PDD-49)	Schedule C-12	Income Tax Effect of Interest for the
18			Projected 12-Month Period Ending
19			April 30, 2027;
20	Exhibit A-13 (PDD-50)	Schedule C-13	Interest Synchronization Adjustment
21			for the Projected 12-Month Period
22			Ending April 30, 2027;
23	Exhibit A-75 (PDD-51)		Regulatory Asset and Amortization
24			Expense of the PowerMiDrive and
25			PowerMiFleet for the Projected
26			12-Month Period Ending
27			April 30, 2027;
28	Exhibit A-76 (PDD-52)		Regulatory Asset and Amortization
29			of Karn and Campbell Plant
30			Retention and Separation Costs for
31			the Projected 12-Month Period
32			Ending April 30, 2027;
33	Exhibit A-77 (PDD-53)		Regulatory Asset and Amortization
34			Expense of the Net Book Value of
35			Campbell Plant 1, 2 , and 3 for the
36			Projected 12-Month Period Ending
37			April 30, 2027;

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Exhibit A-78 (PDD-54) Regulatory Asset and Amortization Expense of Karn and Campbell Decommissioning Costs for the Projected 12-Month Period Ending April 30, 2027;

Exhibit A-79 (PDD-55) Regulatory Asset and Amortization Expense of the Karn, Campbell, and Classic 7 Ash Disposal Costs for the Projected 12-Month Period Ending April 30, 2027;

Exhibit A-80 (PDD-56) Regulatory Asset and Amortization Expense of the Pension and OPEB Volatility Mechanism, for the Projected 12-Month Period Ending April 30, 2027; and

Exhibit A-81 (PDD-57) Campbell Regulatory Asset – Return On for the Projected 12-Month Period Ending April 30, 2027.

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 period 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 Breuring is sponsoring sales, load, and customer data (Schedule E) exhibits. Company witness Emily A. Davis is sponsoring the cost-of-service study. Company witness Laura M. Connolly is sponsoring present and proposed revenue. Company witness Brittani A. Gray is sponsoring the proposed tariff sheet (Schedule F) exhibits.

Q. Please summarize the key findings for the projected test year exhibits.

A. Exhibit A-11 (PDD-28), Schedule A-1, presents the projected jurisdictional electric revenue deficiency for the 12-month period ended April 30, 2027, as follows:

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(\$ In Thousands)

Rate Base	\$15,367,518
Adjusted NOI	<u>707,746</u>
Overall Rate of Return	4.61%
Required Rate of Return	<u>6.35%</u>
Income Required	\$ <u>975,589</u>
Income Deficiency (Sufficiency)	267,843
Revenue Multiplier	<u>1.3381</u>
Revenue Deficiency (Sufficiency)	\$ 358,395
Return On – Campbell Regulatory Asset	<u>77,486</u>
Total Revenue Deficiency (Sufficiency)	\$ <u>435,881</u>

1 **Q. Why is the jurisdictional electric revenue deficiency for the projected test year the**
2 **same as the Total Company projected revenue deficiency?**

3 A. The total Company revenue deficiency for the projected test year is considered 100%
4 jurisdictional. Currently, there is only one contract treated as non-jurisdictional. The
5 contract utilizes the General Meter Lighting tariff rate for all charges on the bill, except for
6 a two-mil discount on the energy charge. While this contract remains in place, the
7 Company has included its projected revenues and the value of the discount as
8 miscellaneous revenues in the instant case.

9 **Q. What inflation factors is the Company using in its presentation?**

10 A. The Company is using inflation factors of 2.10% for 2025, 2.40% for 2026, and 2.40% for
11 2027,¹ as forecasted by S&P Global Market Intelligence and reported in the November

¹ 0.8% for 4-month proration

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2024 edition of its publication *U.S Economic Outlook*. S&P Global Market Intelligence is a leader in economic and financial analysis, forecasting, and market intelligence.

Q. Has the Company provided a summary of where these inflation factors have been used in the case?

A. Yes. Exhibit A-13 (PDD-42), Schedule C-5.1, provides a summary of the inflation included in Other O&M Expenses in the case.

Q. How has Consumers Energy addressed the MPSC's filing requirement to reconcile the projected test year to the most recent calendar year?

A. The following is a list of exhibits that reconcile the projected test year to the historical:

- i. Exhibit A-11 (PDD-30), Schedule A-3;
- ii. Exhibit A-12 (PDD-34), Schedule B-4;
- iii. Exhibit A-13 (PDD-37), Schedule C-1.1; and
- iv. Exhibit A-13 (PDD-41), Schedule C-5.

Q. Please explain Exhibit A-11 (PDD-29), Schedule A-2.

A. This exhibit provides the financial metrics and statistics for the projected test year as required by the MPSC's filing requirements. Column (b) shows the metrics assuming no rate relief is granted. Column (c) shows the metrics assuming the Company's full rate relief request is granted.

Q. Please explain Exhibit A-11 (PDD-30), Schedule A-3.

A. This exhibit presents the projected test year revenue deficiency for Consumers Energy of \$435.9 million (line 11, column (f)). Column (d) of the exhibit presents pertinent rate base and rate of return amounts for the historical period. Column (e) shows the changes resulting from adjustments supported by the various Company witnesses that were made

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1 in developing the projected test year revenue deficiency. Column (f) then displays the
2 projected test year rate base, income requirement, and revenue requirement.

3 **Q. What are the major differences between the historical year and the projected test year**
4 **results shown on Exhibit A-11 (PDD-30), Schedule A-3?**

5 A. The comparison of historical and projected results in Exhibit A-11 (PDD-30), Schedule
6 A-3, shows that rate base increases by \$1.1 billion (line 3) and the rate of return increases
7 from 5.86% to 6.35% (line 4). In addition, the adjusted NOI (line 6) decreases by
8 \$125.8 million when moving from the historical year to the projected test year.

9 **Q. Please describe Exhibit A-12 (PDD-31), Schedule B-1.**

10 A. Exhibit A-12 (PDD-31), Schedule B-1, is a summary presentation of the projected test year
11 average rate base of \$15.4 billion as shown on line 7.

12 **Q. Please describe Exhibit A-12 (PDD-32), Schedule B-2.**

13 A. Exhibit A-12 (PDD-32), Schedule B-2, presents the total utility plant for the projected test
14 year. The total on line 24 is carried forward to line 1 on Exhibit A-12 (PDD-31),
15 Schedule B-1.

16 **Q. Please describe how the projected test year average plant and related amounts were**
17 **developed.**

18 A. Utility plant and reserve balances for the projected test year were developed by calculating
19 a 13-month average of the balances as of April 30, 2026 through April 30, 2027. Actual
20 calendar year 2024 balances for construction work-in-progress ("CWIP"), gross plant, and
21 accumulated depreciation were used as the starting point. Projected capital expenditures
22 (including Allowance for Funds Used During Construction ("AFUDC")) and plant
23 additions were added for the calendar year 2025, calendar year 2026, and the first four

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months of 2027; followed by adjustments for projected retirements, depreciation expense, cost of removal, and the calculation of the ending balances for CWIP, plant, and the accumulated provision for depreciation.

Q. Did you make any adjustments to the December 2024 balances used as the starting point?

A. Yes. I removed the historical balances for Campbell Units 1, 2, and 3, to incorporate them under the regulatory asset treatment explained in Section III of my direct testimony. I removed the impacts on the historical plant in-service, construction work in progress, and accumulated depreciation balances of calendar year 2024 expenditures associated with the Company's River Hydro investments. As explained by Company witness Heidi J. Myers, the Company is proposing to extend the hydro revenue requirement deferral approved in Case No. U-21585. The removal of the 2024 hydro expenditures is required because this deferral began in 2024.

Q. Please describe Exhibit A-12 (PDD-33), Schedule B-3.

A. Exhibit A-12 (PDD-33), Schedule B-3, presents the projected depreciation reserve for the projected test year by functional group. The total on line 17 is carried forward to line 2 on Exhibit A-12 (PDD-31), Schedule B-1. The increase in the projected accumulated depreciation provision for the projected test year incorporates depreciation expense calculated using book depreciation rates approved by the Commission in Case No. U-20849. The calculated depreciation expense and associated accumulated depreciation presented also uses depreciation rates for the Ludington Hydro facility approved in Case No. U-20844.

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1 **Q. Please explain Exhibit A-12 (PDD-34), Schedule B-4.**

2 A. Exhibit A-12 (PDD-34), Schedule B-4, develops the Company's proposed projected test
3 year balance sheet working capital requirement. The starting point is the 13-month average
4 historical December 2024 working capital shown in column (b). The December 2024
5 average balances are then adjusted to reflect changes to:

6 i. Pension and Other Post-Employment Benefits ("OPEB") balances based on
7 projections sponsored by Company witness Kendra K. Grob, and the
8 regulatory asset and liability related to the volatility mechanism;

9 ii. Accrued tax balances;

10 iii. Prepaid cloud computing balances sponsored by Company witness Stacy H.
11 Baker;

12 iv. Regulatory asset balances for PowerMIDrive and PowerMIFleet deferred
13 costs;

14 v. Regulatory asset balances for D.E. Karn ("Karn") and J.H. Campbell
15 ("Campbell") retention costs, Campbell plant's net book value, and various
16 coal plants' decommissioning and ash disposal costs;

17 vi. Cash balance sponsored by Company witness Bleckman; and

18 vii. Deferred debits for a software implementation deferral sponsored by
19 Company witness Baker.

20 **Q. Why did the Company use the balance sheet approach in determining the working**
21 **capital requirement?**

22 A. Use of the balance sheet method was mandated by the Commission in Case No. U-7350.
23 The Commission, in Case No. U-15895, also required that this method be used to develop
24 the allowance for working capital.

25 **Q. Please describe Exhibit A-12 (PDD-35), Schedule B-5.**

26 A. Exhibit A-12 (PDD-35), Schedule B-5, provides a summary of capital spending as
27 supported by various Company witnesses. This exhibit provides capital spending for the

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bridge year and projected test year as well as the projected and approved spending during the previous rate case test year in Case No. U-21585.

Q. Please describe Exhibit A-13 (PDD-36), Schedule C-1.

A. Exhibit A-13 (PDD-36), Schedule C-1, presents the calculation of adjusted NOI for the projected test year of \$707.7 million as shown on line 19. Total operating revenues (line 4) are netted against total operating expenses (line 13) to arrive at net operating income on line 14. Further adjustments are made on lines 15, 17, and 18, which utilize normal ratemaking practices to arrive at adjusted NOI on line 19.

Q. Please explain Exhibit A-13 (PDD-37), Schedule C-1.1

A. Exhibit A-13 (PDD-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 (m), NOI in column (n), AFUDC in column (o), and adjusted NOI in column (p). The exhibit begins with the historical year on line 1, normalizing adjustments to the historical year on lines 2 through 15, and projected test year adjustments on lines 17 through 28. Total adjusted NOI for the projected test year is shown on line 29, column (p). In general, the revenue and expense adjustments are shown with their accompanying tax impacts to arrive at the adjusted NOI. The historical year NOI of \$977.9 million on line 1, column (p), ties to the historic NOI on line 17 of Exhibit A-3 (PDD-9), Schedule C-1.

Q. Please explain the normalizing adjustments on Exhibit A-13 (PDD-37), Schedule C-1.1.

A. The adjustments located on lines 2 through 15 are made to comply with prior Commission orders and follow traditional ratemaking adjustments to historical booked results such as:

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1 (i) removing regulatory disallowances; (ii) normalizing for unusual, one-time, or
2 out-of-period items; (iii) bringing certain revenues and expenses “above the line”;
3 (iv) adjusting historical revenues to reflect “normal” weather; and (v) performing related
4 adjustments to income taxes. Additional adjustments include certain O&M expense
5 normalizations to better align the historical year with expected expense amounts in the
6 projected test year. These adjustments are supported by my exhibits and supporting
7 workpapers, and from the exhibits of other Company witnesses.

8 The historical year adjusted NOI on Exhibit A-13 (PDD-37), Schedule C1.1,
9 line 16, column (p), of \$829.5 million, ties to historic NOI on line 33, column (c), of Exhibit
10 A-3 (PDD-9), Schedule C-1.

11 **Q. How were the projected test year adjustments on Exhibit A-13 (PDD-37), Schedule**
12 **C-1.1, developed?**

13 A. These adjustments represent the movement from the historical year adjusted NOI to the
14 projected test year NOI. The adjustments on lines 17 through 28 are developed from my
15 exhibits and supporting workpapers, and from the exhibits of other Company witnesses.
16 The projected test year NOI on line 29 is the result of netting the projected test year
17 adjustments on lines 17 through 28 against the historical year adjusted NOI on line 16. The
18 projected test year adjusted NOI of \$707.7 million on line 29, column (p), ties to the
19 projected test year adjusted NOI on Exhibit A-13 (PDD-36), Schedule C-1, line 19.

20 **Q. Please explain the test year adjustments made for the projected test year on Exhibit**
21 **A-13 (PDD-37), Schedule C-1.1.**

22 A. Lines 17 through 19 represent the changes in revenues when moving to the projected test
23 year and are supported by Company witness Breuring. Line 20 represents an adjustment

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1 to the power supply costs shown on Exhibit A-13 (PDD-40), Schedule C-4, to align the
2 projected test year Power Supply Cost Recovery ("PSCR") expense with the projected test
3 year PSCR revenues proposed by Company witness Breuring.

4 Line 21 represents the change in other O&M expenses from the adjusted historical
5 year to the projected test year and are supported by Company witnesses Stacy H. Baker,
6 Richard T. Blumenstock, Jessica R. Byrom, Amy M. Conrad, Matthew J. Foster, Alex M.
7 Gast, Kendra K. Grob, Quentin A. Guinn, Michael P. Kelly, and Sara E. Stewart. The
8 adjustments are detailed on Exhibit A-13 (PDD-41), Schedule C-5 and Exhibit A-13
9 (PDD-42), Schedule C-5.1.

10 Line 22 represents the change in the book depreciation expense from the adjusted
11 historical year to the projected test year. The Company used the Commission-approved
12 book depreciation rates, projected capital expenditures, and assumed plant retirements to
13 determine the depreciation expense adjustment necessary to arrive at an appropriate level
14 of book depreciation expense for the projected test year. The adjustment on line 22
15 increases depreciation expense from the historical period due to new capital investment.

16 Line 23 represents an adjustment to real and personal property taxes to the projected
17 test year expense level as supported by Company witness Brian J. VanBlarcum and shown
18 on Exhibit A-13 (PDD-44), Schedule C-7, line 1.

19 Line 24 represents the change in historical year payroll and other general taxes to
20 the projected test year amount as shown on Exhibit A-13 (PDD-44), Schedule C-7, lines 6
21 and 15.

22 Line 25 represents city income tax adjustments to the projected test year level city
23 income tax expense as shown on Exhibit A-13 (PDD-47), Schedule C-10, line 18.

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1 Line 26 reflects the impact of Michigan Corporate Income Tax (“MCIT”). The
2 projected test year MCIT expense is shown on Exhibit A-13 (PDD-46), Schedule C-9,
3 line 20.

4 Line 27 represents the Federal Income Tax (“FIT”) adjustments which result from
5 the other changes in revenue and expense levels for the projected test year. Also reflected
6 are the differences between the FIT expense calculated at the current federal statutory rate
7 and the actual total income tax expense. FIT expense is shown on Exhibit A-13 (PDD-45),
8 Schedule C-8, line 50.

9 Line 28 represents an adjustment to AFUDC from the adjusted historical year to
10 the projected test year. The projected test year AFUDC is shown on Exhibit A-13
11 (PDD-48), Schedule C-11. AFUDC is an accounting convention that recognizes the costs,
12 both interest and equity, of financing certain construction projects. The recognition is
13 through the transfer of interest and equity cost from the income statement to CWIP on the
14 balance sheet. The interest and equity costs are capitalized in the same manner as
15 construction labor and material costs when the project is closed to plant-in-service. The
16 criteria for applying AFUDC to a construction project require on-site construction activities
17 of more than six months duration and an estimated plant cost (excluding AFUDC) in excess
18 of \$50,000. AFUDC charged to projects addressing compliance with environmental clean
19 air requirements are not included in this ratemaking adjustment, which is consistent with
20 the Commission’s ratemaking treatment. AFUDC increases revenue and NOI, reducing
21 the amount of rate relief requested in the case and is designed to offset the return built into
22 the case for CWIP that is eligible for AFUDC treatment.

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1 **Q. Please describe Exhibit A-13 (PDD-38), Schedule C-2.**

2 A. Exhibit A-13 (PDD-38), Schedule C-2, shows the development of the revenue multiplier
3 for the projected test year. The revenue multiplier is a factor that converts a utility's
4 after-tax income deficiency (or sufficiency) into the required change in pre-tax revenue
5 requirement. For the projected test year, the FIT rate is 21.00%, the MCIT rate is 5.24%,
6 and the CIT rate is 0.16%. The resulting revenue multiplier is 1.3381.

7 **Q. Please explain the projected revenues shown on Exhibit A-13 (PDD-39), Schedule C-3.**

8 A. Total projected revenues are shown on line 4. Lines 1, 2, and 3 of the exhibit present the
9 sales, wholesale, and other electric revenues that are supported by Company witness
10 Breuring. The total on line 4 is carried forward to the Company's projected adjusted NOI
11 presentation on Exhibit A-13 (PDD-36), Schedule C-1.

12 **Q. Please explain Exhibit A-13 (PDD-40), Schedule C-4.**

13 A. This exhibit presents the projected test year power supply costs that are supported by
14 Company witness Megan L. Metz. This total is carried forward to line 5 of the Company's
15 projected adjusted NOI presentation on Exhibit A-13 (PDD-36), Schedule C-1.

16 **Q. Please explain Exhibit A-13 (PDD-41), Schedule C-5.**

17 A. Exhibit A-13 (PDD-41), Schedule C-5, presents the other O&M expense for the projected
18 test year as compared to the historical year. The amounts on lines 1 through 23 were
19 provided by Company witnesses Kelly, Stewart, Blumenstock, Guinn, Baker, Byrom, Gast,
20 Grob, Foster, Conrad, and Breuring. These amounts are supported in their respective direct
21 testimony and exhibits. The amounts on line 24 reflect interest expense on security
22 deposits.

1 **Q. Please explain Exhibit A-13 (PDD-42), Schedule C-5.1.**

2 A. Exhibit A-13 (PDD-42), Schedule C-5.1, provides a summary of inflation and labor merit
3 increases included in other O&M expense. Amounts projected using a method other than
4 inflation and merit are included in column (g). As indicated on this exhibit, various
5 Company witnesses provide detailed calculation of the inflation amounts included in this
6 summary exhibit.

7 **Q. Please explain Exhibit A-13 (PDD-43), Schedule C-6.**

8 A. Exhibit A-13 (PDD-43), Schedule C-6, presents the projected depreciation & amortization
9 expense. Depreciation expense is calculated using book depreciation rates approved by the
10 Commission in Case No. U-20849. The calculated depreciation expense and associated
11 accumulated depreciation presented also uses depreciation rates for the Ludington Hydro
12 facility approved in Case No. U-20844. I discuss the calculation of the amortizations in
13 lines 17 through 24 of Exhibit A-13 (PDD-43), Schedule C-6, in Section III of my direct
14 testimony.

15 **Q. Does the Company have a depreciation case pending before the Commission that**
16 **could impact depreciation expense and therefore, the revenue deficiency in this**
17 **proceeding?**

18 A. No.

19 **Q. Please explain Exhibit A-13 (PDD-44), Schedule C-7, through Exhibit A-13 (PDD-48),**
20 **Schedule C-11.**

21 A. These exhibits present the following: (i) projected general taxes; (ii) projected FIT;
22 (iii) projected state income taxes; (iv) projected other (or local) taxes; and (v) projected

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AFUDC. The total from each schedule is carried forward to the Company's projected NOI presentation on Exhibit A-13 (PDD-37), Schedule C-1.

Q. Please describe Exhibit A-13 (PDD-49), Schedule C-12.

A. Exhibit A-13 (PDD-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 (PDD-50), Schedule C-13.

A. Exhibit A-13 (PDD-50), Schedule C-13, shows the calculation of the tax effect of the interest synchronization adjustment for the projected test year.

Q. Why are Exhibit A-13 (PDD-49), Schedule C-12, and Exhibit A-13 (PDD-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. REGULATORY ASSETS AND OTHER ACCOUNTING TREATMENTS

A. PowerMIDrive and PowerMIFleet Permanent Programs and Pilot Programs

Q. Has the Commission approved deferred accounting treatment for the PowerMIDrive and PowerMIFleet permanent programs and pilot programs?

A. In Case Nos. U-20134 and U-20697, the Commission approved deferred accounting for expenditures associated with the PowerMIDrive and PowerMIFleet pilot programs. The approach adopted by the Commission envisioned a prudence review of actual expenditures after which the amortization expense, based on a five-year amortization to begin the year after the actual expenditures are recorded, would be included in rates. In addition, the Commission allowed for the deferred balance to be included in rate base earning a return

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1 at the authorized rate of return. The Commission also extended this deferred accounting
2 treatment to the permanent programs and reaffirmed the pilot program treatment in
3 its approval of the Settlement Agreement in Case No. U-21224. Most recently, the
4 Commission approved the continuation of the regulatory asset treatment in its final Order
5 in Case. No U-21585.

6 **Q. Please describe Exhibit A-75 (PDD-51).**

7 A. Exhibit A-75 (PDD-51) provides the calculation of the projected test year amortization
8 expense, and the projected test year average regulatory asset balances associated with the
9 PowerMIDrive and the PowerMIFleet Programs.

10 **Q. Describe how the projected test year amortization expense and average deferred**
11 **balance for the PowerMIDrive program was calculated on Exhibit A-75 (PDD-51).**

12 A. Line 1 provides the actual deferred expenditures for the program through 2024. The
13 program expenditures are supported by Company witness Myrom. Lines 2 through 7 show
14 the amortization expense by year. Line 8 shows the total amortization expense for each
15 calendar year, while line 15 shows the proration for the projected test year ending April 30,
16 2027. The test year amortization expense of \$3.7 million has been included in the projected
17 amortization expense on Exhibit A-13 (PDD-43), Schedule C-6. Line 18 shows the
18 calculation of the average rate base amount for the test year of \$8.2 million, which has been
19 included in the projected working capital on Exhibit A-12 (PDD-34), Schedule B-4.

20 **Q. Describe how the projected test year amortization expense and average deferred**
21 **balance for the PowerMIFleet program was calculated on Exhibit A-75 (PDD-51).**

22 A. Line 9 provides the actual deferred expenditures for the program through 2024. Lines 10
23 through 13 show the amortization expense by year. Line 14 shows the total amortization

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1 expense for each calendar year, while line 16 shows the proration for the projected test year
2 ending April 30, 2027. The test year amortization expense of \$1.8 million has been
3 included in the projected amortization expense on Exhibit A-13 (PDD-43), Schedule C-6.
4 Line 19 shows the calculation of the average rate base amount for the test year of
5 \$4.0 million, which has been included in the projected working capital on Exhibit A-12
6 (PDD-34), Schedule B-4.

7 **B. Karn Units 1 and 2 and Campbell Units 1, 2, and 3**
8 **Retention Costs**

9 **Q. Please describe Exhibit A-76 (PDD-52).**

10 A. Exhibit A-76 (PDD-52) calculates the projected test year regulatory asset balance and
11 amortization expense for Karn Units 1 and 2 retention costs as ordered by the Commission
12 in Case No. U-20697. The associated working capital and amortization has been included
13 in the case. The \$0.2 million average rate base amount for the projected test year has been
14 included in the projected working capital on Exhibit A-12 (PDD-34), Schedule B-4, and
15 the \$0.3 million amortization expense has been included in the projected depreciation and
16 amortization expense on Exhibit A-13 (PDD-43), Schedule C-6.

17 Additionally, this exhibit calculates the projected test year regulatory asset balance
18 and amortization expense for Campbell Units 1, 2, and 3 retention costs as agreed in the
19 Company's Integrated Resource Plan ("IRP") Settlement Agreement in Case No. U-21090,
20 approved by the Commission on June 23, 2022, and most recently in the Order in Case No.
21 U-21585. The \$9.6 million average rate base amount for the projected test year has been
22 included in the projected working capital on Exhibit A-12 (PDD-34), Schedule B-4, and
23 the \$8.5 million amortization expense has been included in the projected depreciation and
24 amortization expense on Exhibit A-13 (PDD-43), Schedule C-6.

C. Campbell Plant Net Book Value

Q. Why were the Campbell plant balances removed from the calculation of the projected test year average CWIP, gross plant, and accumulated depreciation?

A. The Settlement Agreement approved by the Commission in Case No. U-21090 on June 23, 2022, established that in the next rate case filed after the conclusion of the IRP case (Electric Rate Case No. U-21389), the actual remaining net book value of Campbell Units 1, 2, and 3 would be removed from plant-in-service and accumulated depreciation accounts and placed into a regulatory asset. Moreover, the agreement set annual amortization to allow for the recovery of the remaining net book value and the decommissioning costs through May 2031 for costs associated with Campbell Units 1 and 2 and through May 2040 for costs associated with Campbell Unit 3. In addition, the Company is allowed the following:

(...) to recover the unrecovered book balance of Campbell Units 1, 2, and 3 through the Company's proposed regulatory asset treatment, with a return equal to the Company's weighted average cost of capital ("WACC") premised on the return on equity approved by the Commission in rate cases prior to the retirement date of those units and a 9.0% return on equity after the retirement date of those units, as part of the Company's electric rates over the current design lives of those units. The 9.0% return on equity will be used to modify the capital structure filed with each rate case and the return on equity will be the only modification to the capital structure used to calculate the return on the regulatory asset after the retirement date of the units. [MPSC Case No. U-21090, June 23, 2022 Order, Exhibit A, page 5.]

The Commission most recently approved the treatment described above in the Order in Case No. U-21585.

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1 **Q. Please describe Exhibit A-77 (PDD-53).**

2 A. Exhibit A-77 (PDD-53) calculates the regulatory asset balance and amortization expense
3 for Campbell Units 1, 2, and 3. The exhibit starts with the regulatory asset balances as of
4 December 31, 2024 for Campbell Units 1 & 2 in column (c), line 3, and for Campbell Unit
5 3 in column (c), line 7. These balances are rolled forward by subtracting the amortization
6 expense for the subsequent periods. The amortization expense is calculated in line 2
7 through May 2031 for Campbell Units 1 and 2. The amortization expense for Campbell
8 Unit 3 is calculated in line 6 through May 2040. Finally, the 13-month average regulatory
9 asset balances for the projected test year period are included on lines 4 and 8, column (f),
10 for Campbell Units 1 & 2 and Campbell Unit 3, respectively.

11 **Q. How are the results of these exhibits included in the instant case?**

12 A. The average rate base amount for the projected test year (\$314.6 million for Campbell
13 Units 1 and 2, and \$773.0 million for Campbell Unit 3) have been excluded from the test
14 year projected working capital on Exhibit A-12 (PDD-34), Schedule B-4. The amortization
15 expense (\$68.6 million for Campbell Units 1 and 2, and \$56.9 million for Campbell Unit
16 3) have been included in the projected depreciation and amortization expense on Exhibit
17 A-13 (PDD-43), Schedule C-6.

18 **Q. Why did the Company exclude Campbell Units 1, 2, and 3 projected regulatory asset**
19 **balances from working capital, and how is the Company addressing the lower return**
20 **on equity approved for the Campbell regulatory asset after the retirement date of the**
21 **units?**

22 A. As noted above, the Settlement Agreement approved by the Commission in Case No.
23 U-21090 requires the overall return on the Campbell regulatory asset to reflect a return on

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equity of 9% after retirement of the units in May 2025. To accomplish this, I have excluded the regulatory asset from the balances underlying the base rate revenue deficiency calculations. Instead, I am supporting a separate return calculation for the Campbell regulatory asset on Exhibit A-81 (PDD-57) with an ROE of 9%. The resulting return on the Campbell regulatory asset is included in the Company's overall revenue deficiency presentation on Exhibit A-11 (PDD-28), Schedule A-1, line 9.

D. Decommissioning and Ash Disposal Costs

Q. Did the Commission approve a regulatory asset treatment for the decommissioning and ash disposal costs for certain coal units?

A. Yes. First, the Settlement Agreement approved by the Commission in Case No. U-20849 established the following:

The decommissioning costs, less salvage value, related to D.E. Karn Units 1 and 2 and the ash disposal costs related to D.E. Karn Units 1 and 2 and the Classic 7 sites (i.e. the three units at the J. R. Whiting Generating Complex near Luna Pier, two units at the B.C. Cobb Generating Plant in Muskegon, and two units at the Karn/Weadock Generating Complex near Bay City) will be recorded, as spent, to a regulatory asset. The Company may request recovery in future base rate proceedings, and upon Commission determination that those costs are reasonable and prudent, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts. [MPSC Case No. U-20849, December 9, 2021 Order, Exhibit A, pages 2-3.]

Second, the Settlement Agreement approved by the Commission in Case No. U-21090 established the following:

[T]he Company will be permitted to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Recovery of

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the associated decommissioning and ash disposal costs will be treated as follows:

a. The decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3 and the ash disposal costs related to Campbell Units 1, 2, and 3 will be recorded, as spent, to a regulatory asset; and

b. The Company may request recovery in future base rate proceedings, and upon Commission determination that the Company has incurred those costs as the result of reasonable and prudent actions, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts. [MPSC Case No. U-21090, June 23, 2022 Order, Exhibit A, page 5.]

Finally, the Settlement Agreement approved by the Commission in Case No. U-21224 provided the following:

The Commission should approve the Company's proposed D.E. Karn Units 1 and 2 decommissioning plan and the amortization of the regulatory asset associated with the Karn Units 1 and 2 decommissioning costs and the Karn Units 1 and 2 and the Classic 7 ash disposal costs. The costs associated with Karn Units 1 and 2 decommissioning will be amortized through 2031 beginning in 2024 and the Karn Units 1 and 2 and Classic 7 ash disposal costs will be amortized over 10 years beginning in 2024. [MPSC Case No. U-21224, January 19, 2023 Order, Exhibit A, page 7.]

Most recently, the Commission approved the treatment described above in the Order in Case No. U-21585.

Q. Please describe Exhibit A-78 (PDD-54) and Exhibit A-79 (PDD-55).

A. Exhibits A-78 (PDD-54) and A-79 (PDD-55) calculate the projected test year regulatory asset balance and amortization expense for the following: (i) Karn Units 1 and 2 decommissioning costs; (ii) Campbell Units decommissioning costs, and (iii) Karn Units 1 and 2, Classic 7, and Campbell Units ash disposal costs. The total of \$133.5 million average rate base amount for the projected test year has been included in the projected

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1 working capital on Exhibit A-12 (PDD-34), Schedule B-4, and the total of \$18.9 million
2 amortization expense has been included in the projected depreciation and amortization
3 expense on Exhibit A-13 (PDD-43), Schedule C-6.

4 **E. Pension/OPEB Volatility Mechanism**

5 **Q. Please explain Exhibit A-80 (PDD-56).**

6 A. Exhibit A-80 (PDD-56) calculates the projected test year regulatory asset and liability
7 balances, and the corresponding amortization expense, related to the Pension and OPEB
8 Volatility Mechanism approved by the Commission in Case Nos. U-21224, U-21389, and
9 U-21585. This volatility mechanism allows the Company to defer for future recovery or
10 refund pension and OPEB expenses above or below approved amounts. The net total of
11 (\$1.8) million average rate base amount for the projected test year has been included in the
12 projected working capital on Exhibit A-12 (PDD-34), Schedule B-4, and the total of
13 (\$0.1) million amortization expense has been included in the projected other O&M expense
14 on Exhibit A-13 (PDD-41), Schedule C-5.

15 **F. SAP S/4HANA Implementation Project Recovery**

16 **Q. Please describe the SAP S4/HANA Project.**

17 A. The SAP S4/HANA Project will modernize the Company's current Enterprise Resource
18 Planning SAP solution that will reach the end of mainstream vendor maintenance on
19 December 31, 2027. The completion of this project is crucial. Operating the system
20 beyond the end of the support date creates significant risks including the inability to comply
21 with regulatory mandates, perform core customer supporting business operations, and
22 apply the latest security patches that are critical for cyber security protection. The project
23 is described in more detail in the testimony of Company witness Baker.

1 **Q. Please describe amounts included for recovery in this rate case related to the SAP**
2 **S4/HANA Project.**

3 A. The Company has included [REDACTED] of bridge year and [REDACTED] of test year
4 capital spending and [REDACTED] of O&M expense in the case. None of the capital
5 spending will close to plant in service during the test year of this case. As a result, the case
6 does not include any of the associated depreciation expense and the return on amounts
7 included in construction work in progress have been offset by allowance for funds used
8 during construction. In other words, there is no financial impact to the case resulting from
9 the capital spending. The O&M expense has a dollar for dollar or [REDACTED] impact on
10 the revenue deficiency.

11 **Q. How does the Company propose to address the O&M expense for this project?**

12 A. The Company is proposing to defer the associated O&M expense for the project and
13 amortize it over 15 years consistent with the life of the assets. This proposal prevents the
14 need for customers to fund spikes in the Company's IT O&M expense during the project
15 and instead smooths the collection over the life of the asset. The deferral will also tie the
16 recovery to the time period over which the spending will provide benefits to the Company
17 and its customers. This is the most appropriate method of recovering the O&M expense
18 related to the project.

19 **Q. If the proposed deferral is approved how will the case be impacted?**

20 A. If the deferral is approved, the revenue deficiency of the case should be lowered by
21 [REDACTED]. As shown on Confidential Exhibit A-86 (PDD-62), this reduction includes
22 the removal of the O&M expense and replaces it with the inclusion of the expense as a
23 deferral in working capital.

1 **Q. Does the implementation of this deferral require any specific accounting approvals?**

2 A. Yes. The proposed deferral would result in a regulatory asset to be amortized over
3 15 years. The Company requests approval to recognize a regulatory asset to record these
4 deferred expenses.

5 **Q. Are there any other requests related to the SAP S4/HANA Project?**

6 A. Yes. The Company also requests a 15-year amortization period for the cloud
7 implementation costs for the SaaS solutions to create consistency of recovery for all aspects
8 of the cost of the SAP S4/HANA Project. This would lengthen the amortization period
9 from being tied to the duration of the initial license to the life of the asset. This provides
10 customer benefit by spreading these costs over a longer period and matching the recovery
11 to the period over which this spending will provide benefit to the Company and its
12 customers.

13 **G. Line Clearing Program Ramp-up**

14 **Q. What is the Company proposing with respect to its LVD Line Clearing Program**
15 **expenditures in this case?**

16 A. The Company is proposing to increase its LVD Line Clearing Program O&M expenditures
17 significantly above historical levels toward attaining a five-year clearing cycle and more
18 aggressive line clearing on targeted three phase primary lines. As discussed by Company
19 witness Stewart, this “ramp-up” in LVD line clearing spending will occur over a five-year
20 period, and at its termination in 2031 the Company expects to maintain a steady-state
21 five-year cycle for its LVD system.

1 **Q. What level of funding is projected for the ramp-up period to achieve the five-year**
2 **cycle?**

3 A. The total O&M projected expense requirements from 2026 through the 2030-2031 test
4 period (the “ramp-up” period) for the entire Line Clearing Program are supported by
5 Company witness Stewart in Figure 13 of her direct testimony. The amounts within Figure
6 13 represent expenditures for both the LVD and HVD system. Witness Stewart bifurcates
7 the expenditures between “total” O&M and “baseline” O&M expenses and explains the
8 methodology to calculate each. The difference between the “total” and “baseline”
9 expenditures represents the incremental (“ramp-up”) costs for the Company to achieve its
10 vision for a 5-year line clearing cycle for the LVD system. The “ramp-up” costs
11 attributable to achieving a five-year line clearing cycle for the LVD system total
12 approximately \$256 million from 2026 through the 2030-2031 test period.

13 **Q. Is the Company seeking recovery of the incremental “ramp-up” expenditures in**
14 **O&M levels in its projected period revenue requirement?**

15 A. No. The Company is seeking approval in this case to defer the “ramp-up” related expenses
16 as a regulatory asset once the “ramp-up” begins and through its completion (i.e., beginning
17 in 2026 and through the 2030-2031 test period). The Company will securitize the
18 regulatory asset when it reaches an appropriate balance. However, the Company’s offer to
19 securitize the balance is conditional upon receiving a return on the deferred expenses at the
20 Company’s prevailing weighted average cost of capital during the “ramp-up” period and
21 until securitization takes place. This requirement and securitization of the deferred expense
22 are supported by Company witness Bleckman.

1 **Q. Why is it appropriate to defer and then securitize the “ramp-up” related Forestry**
2 **expenses?**

3 A. Allowing the deferral of the expenditures above the level that is included in rates approved
4 in this case (the “baseline” O&M expense) will ensure that customers only pay for work
5 that is accomplished. Additionally, the benefits provided by the “ramp-up” will continue
6 for years after the work is completed. Allowing these costs to be deferred and then
7 securitized with a five-year amortization period will better match those benefits to the
8 recovery of the costs. Finally, the securitization of these deferred expenses will lower the
9 cost to customers due to lower cost-of-debt-only financing.

10 **Q. If the proposed deferral is approved how will the case be impacted?**

11 A. If the deferral is approved, the revenue deficiency of the case should be lowered by
12 \$21.4 million. As shown on Exhibit A-82 (PDD-58), this reduction includes the removal
13 of the test year “ramp-up” O&M expense and replaces it with the inclusion of the expense
14 as a regulatory asset in working capital.

15 **Q. Does the implementation of this deferral require any specific accounting approval?**

16 A. Yes. The Company requests approval to recognize a regulatory asset to record these
17 deferred expenses.

18 **IV. DISTRIBUTION DEFERRAL**

19 **Q. Did the Commission approve the deferral of the revenue requirement of certain**
20 **distribution capital spending for the period of March 1, 2024 to February 28, 2025?**

21 A. Yes. In its March 1, 2024 Order in Case No. U-21389, the Commission approved deferred
22 accounting for the return on, return of, and property taxes associated with actual capital
23 spending from March 1, 2024 through February 28, 2025 above the following amounts

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1 until rates were reset in a subsequent case: \$158.4 million for new business, \$147.6 million
2 for reactive demand failures, and \$52.5 million for asset relocations. Subsequently, in its
3 March 21, 2025 Order in Case No. U-21585, the Commission approved to extend the
4 deferral of the revenue requirement associated with capital spending for the
5 aforementioned time period above rate levels until actuals are included in rates. The capital
6 spending amounts approved in Case No. U-21585 were: \$281.1 million for new business,
7 \$188.9 million for reactive demand failures, and \$53.3 million for asset relocations.

8 **Q. Are you sponsoring any exhibits related to the March 1, 2024 to February 28, 2025**
9 **distribution deferral in this case?**

10 A. Yes. Exhibit A-84 (PDD-60) is presented in support of the distribution deferral revenue
11 requirement.

12 **Q. Did the Company have actual capital spending above the amounts included in the**
13 **rates for new business, reactive demand failures, and asset relocation?**

14 A. Yes. As provided on page 2 of Exhibit A-84 (PDD-60), the Company had actual capital
15 spending for the period of March 1, 2024 to February 28, 2025 above the amounts included
16 in rates for all three of the referenced capital spending programs.

17 **Q. Are any of these programs included in the Investment Recovery Mechanism (“IRM”)**
18 **sponsored by Company witness Myers in the instant case?**

19 A. No. The IRM proposal sponsored by Company witness Myers is designed for programs
20 unrelated to new business, reactive demand failures, and asset relocations.

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1 **Q. Have you calculated the return on, return of, and property tax related to the capital**
2 **spending above the amounts included in rates for new business, reactive demand**
3 **failures, and asset relocation?**

4 A. Yes. Exhibit A-84 (PDD-60) provides the calculation of the return on, return of, and
5 property tax expense attributable to the capital spending for the period of March 1, 2024
6 through February 28, 2025 above the amounts approved in Case No. U-21389 and Case
7 No. U-21585. The \$24.3 million total amount was calculated to represent the additional
8 revenue requirement from March 1, 2024 through April 30, 2026, that would have been
9 built into rates if the additional capital spending would have been included.

10 **Q. Was the Company able to record revenue for the full return associated with the**
11 **capital spending above amounts included in the Settlement Agreement?**

12 A. No. Per accounting guidance, the Company was not able to record revenue associated with
13 the return on equity portion of the cost of capital. Revenue related to the return on equity
14 will not be recorded until collected from customers. The regulatory asset account related
15 to this deferral includes the return on equity but there is a contra regulatory asset account
16 that offsets the regulatory asset by the amount related to the return on equity. The regulatory
17 asset account houses the total revenue requirement.

18 **Q. How does the Company propose to collect the total deferral from customers?**

19 A. Similar to the recovery of the deferral surcharge approved in Case No. U-21585, the
20 Company proposes that a 12-month charge be established to collect the \$24.3 million total
21 deferral. The Company further proposes that the charge be implemented for service
22 rendered on and after the effective date of the final order in the instant case and terminating

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1 after 12 months. Company witnesses Davis and Connolly sponsor the allocation and
2 design of the charge, respectively.

3 **Q. Did the Commission approve the deferral of the revenue requirement of certain**
4 **distribution capital spending for the test year ending February 28, 2026?**

5 A. Yes. In its March 21, 2025 Order in Case No. U-21585, the Commission also approved
6 deferred accounting for the return on, return of, and property taxes associated with actual
7 capital spending above the approved amounts for the test year ending February 28, 2026,
8 for new business, reactive demand failures, and asset relocations until actual capital
9 spending is included in rates. The approved amounts for these programs for the test year
10 ending February 28, 2026, are shown in Exhibit A-85 (PDD-61).

11 **Q. Is the Company making a proposal in the instant case regarding the distribution**
12 **deferral mechanism?**

13 A. Yes. The Company is requesting the Commission to approve the following: (i) the
14 continuation of the deferral mechanism approved in Case No. U-21585 for the test year
15 ending April 30, 2027; and (ii) the straight-line amortization of the associated regulatory
16 asset balance.

17 **V. DEMAND RESPONSE**

18 **Q. Please describe Exhibit A-83 (PDD-59).**

19 A. Exhibit A-83 (PDD-59) is a three-page exhibit that calculates the projected test year
20 revenue requirement for DR programs as included in this case. The first page of the exhibit
21 summarizes the total projected test year revenue requirement for DR programs. This first
22 page includes the results of the second and third page. The second page of the exhibit
23 calculates the projected test year revenue requirement for the residential DR programs, and

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1 the third page of the exhibit calculates the projected test year revenue requirement for the
2 commercial and industrial DR program. This exhibit establishes the revenue requirement
3 included in rates as proposed in the instant case. Should the Commission adjust the capital
4 or O&M spending requested for DR, it would be necessary to update this exhibit to reflect
5 those changes. Company witness Connolly is also using this exhibit in the calculation of
6 the proposed DR Surcharge. As described by Company witness Connolly, the revenue
7 requirement for DR is removed from the calculation of base rates and is presenting the
8 recovery of DR revenue requirements through a surcharge, as approved in Case No.
9 U-21585.

10 **Q. Does this conclude your direct testimony?**

11 **A.** Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

EMILY A. DAVIS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

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1 **Q. Please state your name and business address.**

2 A. My name is Emily A. Davis, and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
6 as a Principal Rate Analyst in the Pricing section of the Rates and Regulation Department.

7 **Q. Please describe your educational background and experience.**

8 A. In May 2008 I graduated summa cum laude from Illinois State University with a Bachelor
9 of Science Degree in Economics and a minor in Business Administration. In 2010 I
10 received a Master of Science Degree in Applied Economics with a specialization in
11 Electricity, Natural Gas, and Telecommunications. I joined Consumers Energy as a Senior
12 Rate Analyst in March 2018 and was promoted to my current position in September 2023.
13 Before joining Consumers Energy I held various positions with Nicor Gas and its parent
14 companies including Rate Analyst, Strategic Planning Consultant, and Manager of
15 Regulatory Affairs.

16 **Q. What are your responsibilities as a Principal Rate Analyst for Consumers Energy?**

17 A. I am responsible for conducting analyses in support of the Company’s Cost-of-Service
18 Studies (“COSS”) and developing testimony and exhibits in support of proposals in
19 regulatory proceedings before the Michigan Public Service Commission (“MPSC” or the
20 “Commission”).

21 **Q. Have you previously provided testimony before the Commission?**

22 A. Yes. I have filed testimony on behalf of the Company in the following cases:

23 Case No. U-21389 Electric General Rate Case, Cost-of-Service;

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1	Case No. U-21224	Electric General Rate Case, Cost-of-Service;
2	Case No. U-20963	Electric General Rate Case, Cost-of-Service;
3	Case No. U-20650	Gas General Rate Case, Cost-of-Service;
4	Case No. U-20322	Gas General Rate Case, Cost-of-Service;
5	Case No. U-20287	Federal Tax Cut and Jobs Act Tax Credit B (Gas);
6	Case No. U-20103	Federal Tax Cut and Jobs Act Tax Credit A (Gas); and
7	Case No. U-20102	Federal Tax Cut and Jobs Act Tax Credit A (Electric).

8 **Q. What is the purpose of your direct testimony in this proceeding?**

9 A. The purpose of my direct testimony is to sponsor the Company's electric COSS for the
10 forecasted 12-month period ending April 30, 2027 ("test year") and related proposals.
11 Those proposals include the calculation of the State Reliability Mechanism ("SRM")
12 charge and Substation Ownership Credit ("SOC") as well as the allocation of the Demand
13 Response ("DR"), Electric Rate Case Deferral, and Investment Recovery Mechanism
14 ("IRM") surcharges.

15 **Q. Is the Company proposing any changes to the COSS methodologies previously**
16 **approved by the Commission?**

17 A. Yes. Because the Company is proposing changes to the COSS methodologies approved
18 by the Commission in prior cases, in accordance with the Commission's rate case filing
19 requirements established in Case No. U-18238, the Company is sponsoring two versions
20 of the COSS. The first COSS (Version 1) employs the methodologies previously adopted
21 by the Commission in Case No. U-21585 updated for the financial and other supporting
22 data sponsored by various Company witnesses in this case. The second COSS (Version 2)
23 starts with the Version 1 COSS and incorporates Company proposals to revise the
24 allocation of: (i) Customer Advances, and (ii) Overhead ("OH") line Operating &

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Maintenance (“O&M”) Expenses. I describe these proposals in greater detail in Section III of my direct testimony.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-16 (EAD-1)	Schedule F-1	Electric Cost-of-Service Study – Projected 12-Month Period Ending April 30, 2027 Version 1;

Exhibit A-16 (EAD-2)	Schedule F-1.1	Electric Cost-of-Service Study – Projected 12-Month Period Ending April 30, 2027 Version 2;

Exhibit A-87 (EAD-3)		Capacity Related Cost and Charge Calculation (SRM);

Exhibit A-88 (EAD-4)		Substation Ownership Credit; and

Exhibit A-89 (EAD-5)		Allocation of Surcharges.

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. COST OF SERVICE OVERVIEW

II. TEST YEAR ELECTRIC COSS - VERSION 1

III. TEST YEAR ELECTRIC COSS - VERSION 2

IV. SRM CAPACITY CHARGE CALCULATION

V. SUBSTATION OWNERSHIP CREDIT CALCULATION

VI. ALLOCATION OF SURCHARGES

VII. SUMMARY OF PROPOSALS

I. COST OF SERVICE OVERVIEW

Q. What is a COSS?

A. A COSS is a three-part analysis that quantifies the utility's embedded cost of serving various customer classes. The information provided by the COSS is used to guide the design and development of customer rates.

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 the cost is incurred to provide/support. Consumers Energy's electric functional cost categories are production and distribution. Cost classification involves categorizing costs as demand, customer, or energy related 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. When possible, individual costs that can be traced to a class of customers may be directly assigned to that class. The fundamental principle guiding the assignment of costs in the COSS is cost causation; in other words, the costs assigned to a class or group of customers should reflect how those customers drive or influence the utility's costs. This process is relatively standard across the utility industry and is supported by the National Association of Regulatory Utility Commissioners ("NARUC") Electric Rate Design Manual.

Q. What are the allocation factors and how were they developed?

A. There are 18 input allocation factors (or schedules) and 63 calculated allocation factors that were derived (at least in part) from the input schedules. Each schedule was developed to

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1 allocate to each customer class its utilization of a particular part of the electric system. The
2 schedule numbers are shown in Exhibits A-16 (EAD-1), Schedule F-1, and A-16 (EAD-2),
3 Schedule F-1.1, pages 7 through 12. The allocation factors, expressed as percentages, were
4 applied to the COSS cost line items to calculate class cost responsibility.

5 Of the 18 input allocation schedules, nine (schedules 100-108) are based on energy
6 use measured at different times, seasons, and in total. Three schedules are based on
7 measures of demand including Coincident Peak ("CP") (120 and 121) and Class Peak
8 (127). The remaining schedules (141 through 143, 150, 160, and 170) were developed
9 using test year revenue (141 through 143), sales (150) and customer count (160 and 170)
10 data supplied by Company witnesses Eugene M. Breuring and Laura M. Connolly. The
11 calculated allocation schedules were derived from the input schedules, other categories of
12 assigned costs and/or other information contained within the COSS.

13 **Q. How were the energy and demand allocation schedules developed?**

14 A. A three-year average of historic load profiles (2021, 2022, and 2023) was used to develop
15 an average test year profile for each customer class. The loss factors sponsored by
16 Company witness Michael P. Kelly were applied to the average test year profile to arrive
17 at generation and voltage level usage which was used to develop the allocation schedules.

18 **Q. How were the historic load profiles developed?**

19 A. The Company utilized an external consultant to develop the historic load profiles. The
20 consultant used load research software to arrive at a total class profile using the Company's
21 meter data for each customer class. Depending on the rate, either a sample or all available
22 meter and billing data was utilized to develop the load profiles. Load profiles for street

1 lighting were assumed to follow daylight hours and the profiles for unmetered usage were
2 assumed to be a flat average use per hour.

3 **II. TEST YEAR ELECTRIC COSS – VERSION 1**

4 **Q. Please describe Exhibit A-16 (EAD-1), Schedule F-1.**

5 A. Exhibit A-16 (EAD-1), Schedule F-1, is a 28-page exhibit that contains the results of the
6 Version 1 COSS.

7 **Q. How is Exhibit A-16 (EAD-1), Schedule F-1, organized?**

8 A. A summary of the COSS results can be found on pages 1 through 3 of Exhibit A-16
9 (EAD-1), Schedule F-1. The revenue deficiency/(sufficiency) is shown on line 21 with the
10 total revenue requirement and amount to be collected in base rates (“Proposed Rate Design
11 Revenue” or “PRDR”) on lines 22 and 24 respectively. Lines 25 through 29 break out the
12 PRDR by function and other categories that are used by rate design. Additional rate base
13 and O&M detail can be found on pages 4 through 6 and a list of the allocation schedules
14 can be found on pages 7 through 12. Pages 13 through 28 include the cost line item detail
15 and assigned allocation factors required by the Schedule F-1 template included in the
16 Commission’s Standard Filing Requirements that were approved in Case No. U-18238.

17 **Q. Please provide an overview by major cost category of the allocation factors, last**
18 **approved by the Commission in Case No. U-21585, that were relied on in the**
19 **Version 1 COSS.**

20 A. Production capacity costs were assigned to customers using allocator 220 which weights
21 demand (the highest four CPs) by 75% and total energy by 25% (“4CP 75/0/25”).
22 Production non-capacity costs were allocated on energy use at generation for the associated
23 time periods and seasons. Transmission expense was allocated on 12CP demand (“12CP

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100"). Distribution plant was primarily allocated on Class Peak demand¹ with related costs allocated in a similar manner as the associated plant. General, Common, and Intangible ("GC&I") plant and related costs were allocated on labor. Working capital was primarily allocated on revenue, plant in service, and labor. Customer related and administrative & general expenses were primarily allocated on customer, revenue, and labor allocators. Property tax was allocated in a similar manner as the associated plant and income tax was primarily allocated on pretax net operating income.

Q. Is the Version 1 COSS used for rate design purposes?

A. No. The Version 1 COSS is used for comparison purposes with Version 2 of the COSS which the Company is proposing to use for rate design.

Q. What updates were made to Version 1 of the COSS?

A. The Company made routine updates for historic and test year data including updates to the allocation schedules discussed in Section I of my direct testimony. Where new or additional cost detail was provided, those costs were treated in a manner consistent with current approved methodologies and/or allocated using a method described below. Version 1 of the COSS also incorporates: (a) a correction to the allocation of the PowerMI-Drive ("PMD") - PowerMI-Fleet ("PMF") amortization expense to align with the Commission's approved treatment of PMD-PMF program costs in Case No. U-21389; (b) updated distribution cost categories for land, lines, and substation assets to align with the results of the Electric Asset Categorization ("EAC") report (formerly known as the "Transmission and Distribution" or "T&D" report); and (c) a breakout and allocation of

¹ Meter facilities and services are assigned using allocators based on the number of customers.

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1 certain Digital Customer Operations (“DCO”) project costs in compliance with the Final
2 Order in Case No. U-20963.

3 **A. PMD-PMF Correction**

4 **Q. Please explain the correction to the PMD-PMF amortization expense allocator.**

5 A. In Case No. U-21389 the Commission adopted the Proposal for Decision (“PFD”)
6 recommendation to allocate PMD and PMF costs to customers based on their share of
7 present revenues. In the Company’s last electric rate case (Case No. U-21585) this change
8 was reflected in the Company’s COSS for the PMD and PMF regulatory assets but not the
9 related amortization expense. The Company believes the intent of the Order was to allocate
10 the PMD and PMF regulatory asset and amortization expense using present revenue and
11 has reflected this change in the Version 1 COSS.

12 **B. EAC Report**

13 **Q. Please provide an explanation of the EAC report and how it supports the COSS.**

14 A. The EAC report is a report provided by property accounting that breaks out plant and
15 related depreciation accounts for distribution substations (Federal Energy Regulatory
16 Commission (“FERC”) 361 and 362), batteries (FERC 363), high voltage distribution
17 (“HVD”) overhead (“OH”) and underground (“UG”) lines (FERC 364-367) and land
18 (FERC 360) into more detailed categories. The COSS relies on this report to breakout
19 distribution costs into more detail to facilitate allocating costs to customers. Through a
20 collaborative effort involving property accounting, engineering, and a third-party
21 consultant (PowerPlan) the Company has developed a new report to breakout the
22 aforementioned distribution accounts in this case.

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1 **Q. Why is the Company changing the EAC report?**

2 A. The previous report was built decades ago and relied on a set of Microsoft Access databases
3 and mapping tables to categorize certain distribution assets. A combination of process
4 complexity, outdated technology, and the loss of institutional knowledge made it difficult
5 to continue to maintain and run the report.

6 In an effort to improve the report and increase transparency around how assets are
7 assigned in the COSS, the Company worked with PowerPlan to create a module built into
8 the existing property accounting reporting system to map assets to the identified COSS
9 categories.

10 **Q. Can you provide an overview of the new EAC report process?**

11 A. At a high level, the PowerPlan module first identifies assets that meet certain FERC
12 account and location criteria. Next, property accounting sends a list of those assets to
13 engineering who maps each asset to the appropriate COSS category. That mapping
14 information is then imported back into the module which uses that data to breakout the
15 asset balance and related depreciation for each COSS category. The COSS categories,
16 which were developed in consultation with accounting and engineering, were chosen to
17 capture both asset voltage and the downstream facilities connected to/relying on that asset.
18 Company witness Megan L. Hayward provides testimony that explains how engineering
19 mapped the substation and HVD line assets to each of the COSS categories.

20 **Q. Does the new EAC report have any impact on production costs?**

21 A. Yes. The new EAC report includes a breakout of Generation Step Up (“GSU”) facilities
22 which consist of substations, lines and other assets that support bringing power from
23 generation facilities to the distribution system. While the assets are appropriately classified

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as distribution for FERC accounting purposes they are in service of/driven by investment in production facilities. For this reason, GSU-related distribution plant identified in the EAC report is included in the COSS balance of other production plant.

Q. Please provide a more detailed overview of the changes to the distribution substation (FERC 361 and 362) cost categories.

A. Tables 1 and 2 below contain the COSS substation categories and approved allocators in the Company's prior electric rate case (Case No. U-21585) compared to Version 1 COSS in this case which relies on the new EAC report.

Table 1: Distribution Substations & Equipment (FERC 361-362): U-21585 COSS	
Category	Allocator
HVD (Voltage 1)	Class Peak @ Voltage 1
HVD (Voltage 2)	Class Peak @ Voltage 2
LVD (Distribution)	Class Peak @ Voltage 3

Table 2: Distribution Substations & Equipment (FERC 361-362): Version 1 COSS	
Category	Allocator
HVD (Voltage 1) Bulk Power (Shared V2,3,4)	Class Peak @ Voltage 2
HVD (Voltage 1) Distribution (Shared V3,4)	Class Peak @ Voltage 3
HVD (Voltage 1) (V1 Only)	Class Peak @ Voltage 1 Only
HVD (Voltage 2) Bulk Power (Shared V2,3,4)	Class Peak @ Voltage 2
HVD (Voltage 2) Distribution (Shared V3,4)	Class Peak @ Voltage 3
HVD (Voltage 2) (V2 Only)	Class Peak @ Voltage 2 Only

Where:

Class Peak @ Voltage 1 assigns costs to Voltage 1, 2, 3 and 4

Class Peak @ Voltage 2 assigns costs to Voltage 2, 3 and 4

Class Peak @ Voltage 3 assigns costs to Voltage 3 and 4

Class Peak @ Voltage 1 Only (NEW) assigns costs to Voltage 1

Class Peak @ Voltage 2 Only (NEW) assigns costs to Voltage 2

The new EAC report and resulting COSS provide a more detailed breakout of substation assets than the previous COSS. The new categories list the substation high side voltage² (Voltage 1: 138 kV and Voltage 2: 69 or 46 kV) and the voltage of the downstream

² The voltage feeding or going into the substation

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1 connected facilities that rely on that asset and should be assigned some of those costs. The
2 new report also includes a category for Other Equipment and Facilities which includes
3 spare equipment and mobile substations. Because these assets are not associated with a
4 specific voltage level, they were assigned to the COSS categories³ in Table 2 based on their
5 share of total substation plant in service.

6 While the EAC report includes both new and revised COSS categories, the
7 Company is not changing its reliance on Class Peak based allocators to assign demand
8 related distribution plant including the Company's substation assets. Two of the new
9 COSS categories involve dedicated facilities that serve Voltage 1 and Voltage 2 customers
10 which required the creation of new Class Peak allocators. These new allocators, Class Peak
11 @ Voltage 1 Only and Class Peak at Voltage 2 Only, allocate costs exclusively to those
12 customers.

13 **Q. Please provide a more detailed overview of the changes to the distribution battery**
14 **(FERC 363) cost categories.**

15 A. There were no changes to the breakout of distribution batteries in the COSS. In Case No.
16 U-21585 100% of the distribution batteries were categorized as low voltage distribution
17 ("LVD") Voltage 3 and that continues to be true. The only change from the prior case is
18 that before, batteries were mapped outside of the EAC report and today they are included
19 in the EAC report.

³ GSU was excluded because those facilities do not use mobile substations.

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Q. Please provide a more detailed overview of the changes to the distribution OH line (FERC 364 and 365) cost category.

A. Tables 3 and 4 below contain the COSS high voltage distribution (“HVD”) OH line categories and approved allocators in the Company’s prior electric rate case (Case No. U-21585) compared to Version 1 COSS in this case which relies on the new EAC report.

Table 3: Distribution HVD OH Lines (FERC 364-365): U-21585 COSS	
Category	Allocator
HVD (Voltage 1)	Class Peak @ Voltage 1
HVD (Voltage 2)	Class Peak @ Voltage 2

Table 4: Distribution HVD OH Lines (FERC 364-365): Version 1 COSS	
Category	Allocator
HVD (Voltage 1) (Shared V1,3,4)	Class Peak @ Voltage 1 Excluding 2
HVD (Voltage 1) (Shared V3,4)	Class Peak @ Voltage 3
HVD (Voltage 1) (V1 Only)	Class Peak @ Voltage 1 Only
HVD (Voltage 2) Bulk Power (Shared V2,3,4)	Class Peak @ Voltage 2
HVD (Voltage 2) Distribution (Shared V3,4)	Class Peak @ Voltage 3
HVD (Voltage 2) (V2 Only)	Class Peak @ Voltage 2 Only

Where:

Class Peak @ Voltage 1 Excluding 2 assigns costs to Voltage 1, 3, and 4

The new EAC report and resulting COSS provide a more detailed breakout of HVD OH line assets than the previous COSS. The new categories list the line voltage (Voltage 1: 138 kV and Voltage 2: 69 or 46 kV) in addition to the voltage of the downstream connected facilities that rely on that asset and should be assigned those costs. The lines category also includes Other Equipment and Facilities which were treated in the same manner as the substation Other Equipment and Facilities.

As stated previously, the Company did not change its reliance on Class Peak based allocators. One new HVD OH lines category, Voltage 1 facilities serving HVD Voltage 1 and LVD (Voltage 3 and 4) customers, required the creation of a new Class Peak allocator (Class Peak @ Voltage 1 excluding Voltage 2) to allocate costs to those customers.

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1 **Q. Please provide a more detailed overview of the changes to the distribution UG line**
2 **(FERC 366 and 367) cost category.**

3 A. Tables 5 and 6 below contain the COSS HVD UG line categories and approved allocators
4 in the Company's prior electric rate case (Case No. U-21585) compared to Version 1 COSS
5 in this case which relies on the new EAC report.

Table 5: Distribution HVD UG Lines (FERC 364-365): U-21585 COSS	
Category	Allocator
HVD (Voltage 2)	Class Peak @ Voltage 2

Table 6: Distribution HVD UG Lines (FERC 364-365): Version 1 COSS	
Category	Allocator
HVD (Voltage 1) (V1 Only)	Class Peak @ Voltage 1 Only
HVD (Voltage 2) (Shared V2,3,4)	Class Peak @ Voltage 2
HVD (Voltage 2) (Shared V3,4)	Class Peak @ Voltage 3
HVD (Voltage 2) (V2 Only)	Class Peak @ Voltage 2 Only

6 The new EAC report and resulting COSS categories provide a more detailed breakout of
7 HVD UG line assets than the previous COSS. The new categories list the line voltage
8 (Voltage 1: 138 kV and Voltage 2: 69 or 46 kV) in addition to the voltage of the
9 downstream connected facilities that rely on that asset and should be assigned those costs.
10 As previously stated, the Company is not changing its reliance on Class Peak based
11 allocators which includes HVD UG line plant and related accounts.

12 **Q. Please provide a more detailed overview of the changes to the distribution land**
13 **(FERC 360) cost category.**

14 A. Tables 7 and 8 below contain the COSS land categories and approved allocators in the
15 Company's prior electric rate case (Case No. U-21585) compared to the Version 1 COSS
16 in this case which relies on the new EAC report.

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Table 7: Distribution Land (FERC 360): U-21585 COSS	
Category	Allocator
METC HVD (Voltage 1)	Class Peak @ Voltage 1
HVD (Voltage 1)	Class Peak @ Voltage 1
HVD (Voltage 2)	Class Peak @ Voltage 2
Substation Land & ROW	Class Peak @ Voltage 3

Table 8: Distribution Land (FERC 360): Version 1 COSS	
Category	Allocator
HVD (Voltage 1) Substation Land & ROW	Class Peak @ Voltage 1
HVD (Voltage 1) Other Land & ROW	Class Peak @ Voltage 1
HVD (Voltage 2) Substation Land & ROW	Class Peak @ Voltage 2
HVD (Voltage 2) Other Land & ROW	Class Peak @ Voltage 2
LVD Land & ROW	Class Peak @ Voltage 3

1 In addition to breaking out land by voltage, the new COSS categories differentiate land
2 related to substations and other assets/equipment which aids in the calculation of the
3 Substation Ownership Credit. The breakout of land into the COSS categories above was
4 done in PowerPlan by first classifying land assets as either HVD or LVD and Substation
5 or Other (Non-Substation) based on the accounting sub-account and location number. The
6 allocated costs for the substation and line categories (FERC 361-367) were relied on to
7 breakout the HVD land assets into voltage level detail.

8 **C. DCO Treatment**

9 **Q. How is the COSS treating the DCO project costs included in the Commission's Order**
10 **in Case No. U-20963?**

11 A. In Case No. U-20963 the Commission adopted MPSC Staff's proposal to require that the
12 Company's COSS breakout and allocate the costs associated with the DCO IT projects
13 listed below⁴:

⁴ In the settlement agreement in Case No. U-21224 the parties agreed it was no longer necessary to breakout the Customer Self Service Mobile Application costs because the project benefits all customers.

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- Move In/Move Out (“MIMO”) 3.0⁵;
- Commercial and Industrial (“C&I”) Online Account Management; and
- MIMO Digital Redesign.

Q. Please provide the test year costs for these DCO projects.

A. The test year costs for these projects are shown in Table 9 below:

Table 9: DCO Projects Test Year Cost Detail (\$ in millions)				
	Plant	Accumulated Depreciation	Depreciation Expense	O&M Expense
MIMO 3.0	\$0.51	\$0.23	\$0.10	-
C&I Online Acct. Mgmt. (now known as Multi-Acct Mgmt.)	\$0.45	\$0.04	\$0.09	\$0.19
MIMO Digital Redesign	-	-	-	-

Q. If the DCO project costs in Table 9 were not separately broken out in the COSS how would they get treated?

A. Plant and related costs for these projects would be included in GC&I cost categories which are functionalized and allocated to all customer classes on the basis of labor. This is how all other DCO IT project costs are treated.

Q. How is the Company allocating the MIMO 3.0 and C&I Online Account Management Project costs in Version 1 of the COSS?

A. The COSS is allocating MIMO 3.0 project costs to the residential customer class because this project was developed to give residential customers a tool for self-service MIMO transactions.

In the time since 2021 (Case No. U-20963), when the Company was ordered to breakout the DCO projects, the C&I Online Account Management project scope and name

⁵ Because MIMO 3.0 was combined with another MIMO effort (MIMO-Energy Efficiency) the combined project costs are shown in the COSS

1 have changed. The revised project is referred to as the Multi-Account Online Account
2 Management (“MAOAM”) project. As indicated by the name change, the scope of this
3 project has expanded to give all customers (including residential customers) the ability to
4 manage multiple accounts through a single login. Because this project will support
5 customers across various rate classes the Company believes it should be allocated in the
6 same manner as other IT projects which negates the need to separately identify and
7 breakout costs in the COSS. Accordingly, the Company requests that the Commission no
8 longer require a separate breakout of costs for this project in future cases.

9 **III. TEST YEAR ELECTRIC COSS – VERSION 2**

10 **Q. Please describe Exhibit A-16 (EAD-2), Schedule F-1.1.**

11 A. Exhibit A-16 (EAD-2), Schedule F-1.1, is a 28-page exhibit that summarizes the Test Year
12 COSS – Version 2. Version 2 of the COSS starts with Version 1 and incorporates Company
13 proposals to: (i) provide a more detailed breakout and allocation of Customer Advances;
14 and (ii) update the allocation of OH line O&M expenses. The 28 pages of Exhibit A-16
15 (EAD-2), Schedule F-1.1, are organized in the same manner as the 28 pages of Exhibit
16 A-16 (EAD-1), Schedule F-1.

17 **A. Customer Advances**

18 **Q. What are Customer Advances and how are they allocated in the COSS?**

19 A. Customer Advances are potentially refundable customer contributions that are made to
20 offset the cost of extending facilities to serve a customer. In the COSS, Customer
21 Advances are treated as a reduction to Rate Base and are currently allocated to customers
22 based on their share of total distribution plant in service (Allocator 309).

1 **Q. How is the Company proposing to allocate Customer Advances in Version 2 of the**
2 **COSS?**

3 A. With the updated EAC report and breakout of distribution assets into more detailed
4 categories, the Company believes it is appropriate to include a more detailed breakout of
5 the Customer Advances that fund those assets. The Version 2 COSS breaks out Customer
6 Advances by the customer's connected voltage level (e.g. Voltage 1, 2, or LVD) and
7 allocates the credit to that same group of customers using Class Peak.

8 **Q. What is the impact of the Company's Customer Advances proposal in the COSS?**

9 A. The impact of this proposal is shown in Table 11 below.

10 **B. Allocation of Distribution O&M**

11 **Q. How is the Company currently allocating Distribution O&M Expenses in the COSS?**

12 A. The majority of Distribution O&M expenses in the COSS are broken out by FERC account
13 and in some cases voltage level. Table 10 below summarizes the current (Version 1) and
14 proposed allocation of Distribution O&M in FERC Accounts 582-586 and 591-597 in the
15 COSS. As shown in Table 10, the majority of Distribution O&M expenses are currently
16 allocated to rate classes based on their assignment of related plant in service ("PIS")
17 accounts. Voltage 1 substation Operating Expenses (FERC 582), for example, are
18 allocated to each rate class in proportion to their assignment of Voltage 1 substation PIS.
19 The logic underlying this approach is reasonable; if a group of customers use and/or drive
20 a large share of investment in a particular asset, it follows that they are responsible for or
21 cause a similar proportion of O&M to maintain that asset.

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Table 10: Breakout and Allocation of Distribution O&M Expense in COSS		
Expense	Version 1 (Current) Allocator	Version 2 (Proposed) Allocator
OPERATING EXPENSES		
582 Substation		
HVD (Vlt. 1)	PIS: HVD (Vlt. 1) Substations	-
HVD (Vlt. 2)	PIS: HVD (Vlt. 2) Substations	-
583 Overhead (OH) Lines		
HVD (Vlt. 1)	4CP Dmd @ Generation	PIS: HVD (Vlt. 1) OH Lines
HVD (Vlt. 2)	Class Peak @ Vlt. 2	PIS: HVD (Vlt. 2) OH Lines
LVD	PIS- OH (LVD & HVD) Lines & Svc	PIS: LVD OH Lines & Svc
584 Underground (UG) Lines		
HVD (Vlt. 1)	PIS: HVD (Vlt. 1) UG Lines	-
HVD (Vlt. 2)	PIS: HVD (Vlt. 2) UG Lines	-
LVD	PIS: LVD Distribution UG Lines	-
585 Streetlight	PIS: Streetlighting Equipment	-
586 Metering	PIS: Meters	-
MAINTENANCE EXPENSES		
591 Structures		
HVD (Vlt. 1)	PIS: HVD (Vlt. 1) Substations	-
HVD (Vlt. 2)	PIS: HVD (Vlt. 2) Substations	-
592 Substations		
HVD (Vlt. 1)	PIS: HVD (Vlt. 1) Substations	-
HVD (Vlt. 2)	PIS: HVD (Vlt. 2) Substations	-
593 Overhead (OH) Lines		
HVD (Vlt. 1)	4CP Dmd @ Generation	PIS: HVD (Vlt. 1) OH Lines
HVD (Vlt. 2)	Class Peak @ Vlt. 2	PIS: HVD (Vlt. 2) OH Lines
LVD	PIS- OH (LVD & HVD) Lines & Services	PIS: LVD OH Lines & Svc
594 Underground (UG) Lines		
HVD (Vlt. 1)	PIS: HVD (Vlt. 1) UG Lines	-
HVD (Vlt. 2)	PIS: HVD (Vlt. 2) UG Lines	-
LVD	PIS: LVD Distribution UG Lines	-
595 Line Transf.	PIS: Line Equipment	-
596 Streetlight	PIS: Streetlighting Equipment	-
597 Meters	PIS: Meters	-

Q. What changes to the allocation of Distribution O&M Expenses is the Company including in the Version 2 COSS?

A. The Company is proposing new allocators for FERC accounts 583 and 593 (OH line) O&M expenses to be consistent with the logic and allocation of costs for similar distribution

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O&M accounts. The proposed Version 2 allocators for each voltage subcategory are shown in Table 10.

Currently Voltage 1 OH line O&M is allocated using a 4CP allocator which is not used to allocate any other distribution related costs in the COSS. The Company is instead proposing to allocate these costs using Voltage 1 OH line PIS. Voltage 2 OH line O&M is currently being allocated using Class Peak @ Voltage 2 which would be reasonable if all Voltage 2 OH line PIS were assigned using that allocator but that is not the case. In Version 2, the Company is proposing to allocate these costs using Voltage 2 OH line PIS. Finally, LVD OH line O&M is currently being allocated using a PIS allocator that includes both LVD and HVD PIS which causes HVD customers to be assigned LVD related O&M. In Version 2 the Company is proposing to allocate these costs using LVD OH line and services PIS.

Q. What is the impact of the Company's proposed changes to the allocation of OH line O&M expenses in the COSS?

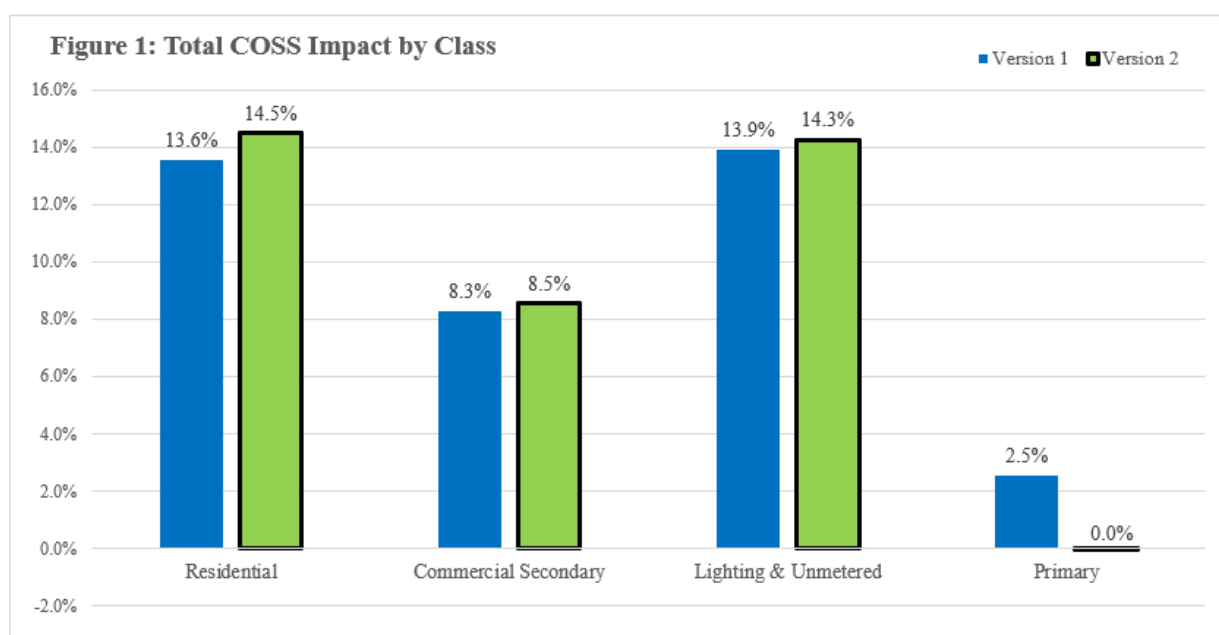
A. The impact of these proposed changes are summarized in Table 11 below.

Q. What is the total impact of the Company's Version 2 proposals on the different COSS rate classes?

A. The impact of each of the Company's proposals is summarized in Table 11 and illustrated in Figure 1 which compare Present Revenue to the PRDR by service class.

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Table 11: Summary of COSS Impacts by Class (\$ in millions)				
Description	Residential	Commercial Secondary	Lighting	Primary
Present Revenue	2,321.4	1,105.3	39.3	968.1
Version 1	314.6	91.3	5.5	24.5
Total Version 1	\$2,636.0	\$1,196.5	\$44.8	\$992.6
	13.6%	8.3%	13.9%	2.5%
+ Customer Advances	1.6	0.6	0.1	(2.3)
+ Distribution O&M Changes	19.9	2.5	0.0	(22.5)
Total Version 2 Proposed	\$2,657.6	\$1,199.6	\$44.9	\$967.8
	14.5%	8.5%	14.3%	0.0%



As illustrated in Figure 1 above, the Company's proposed Version 2 COSS would increase Residential, Commercial Secondary, and Lighting costs by 0.9%, 0.2% and 0.4% respectively compared to Version 1 of the COSS. Primary costs would decrease 2.5%.

IV. SRM CAPACITY CHARGE CALCULATION

Q. Please describe Exhibit A-87 (EAD-3).

A. Exhibit A-87 (EAD-3) shows the calculation of the capacity-related costs and SRM Charge. To arrive at the total capacity-related costs (line 10), non-capacity related costs

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(line 9) are subtracted from total production costs (line 1) included in the Test Year COSS. The total capacity-related costs (line 10) are then offset by the projected revenue (line 16) less associated fuel cost (line 17) and the SRM reconciliation amount (line 19) to arrive at the net capacity cost (line 20). The inclusion of a SRM reconciliation in the calculation of the SRM Capacity Charge is new in this case and was included to comply with the Commission Order in Case No U-21585. The calculation of the SRM reconciliation amount was provided by Company witness Megan L. Metz. To arrive at the Capacity Charge, the net capacity cost (line 20) was divided by the demand provided by Company witness Metz (line 21). The resulting SRM Capacity Charge is \$116.17/MW-Day.

The total non-capacity related cost (line 9), total revenue less fuel cost (line 18), and net capacity cost (line 20) from Exhibit A-87 (EAD-3), are the same values that appear on lines 25 through 27 of Exhibit A-16 (EAD-1), Schedule F-1 and Exhibit A-16 (EAD-2), Schedule F-1.1. Company witness Connolly uses these numbers to breakout capacity-related and non-capacity related power supply charges for full-service customers in accordance with the Commission's November 21, 2017 Order in Case No. U-18239.

V. SUBSTATION OWNERSHIP CREDIT CALCULATION

Q. Please describe Exhibit A-88 (EAD-4).

A. Exhibit A-88 (EAD-4) provides the calculation of the SOC given to customers who own their own substations. The calculation takes the substation costs that have been allocated to GPD, GPTU, and EIP customers on Voltage 1 and Voltage 2 and determines the cost on a per kW basis for each voltage level. Support for the cost detail can be found in WP-EAD-124-125 which relies on Exhibit A-16 (EAD-2), Schedule F-1.1, Test Year COSS –

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Version 2. Because the COSS distribution categories were revised with the EAC report, the cost categories in WP-EAD-124-125 were updated to capture the new cost detail.

Lines 1 through 5 in Exhibit A-88 (EAD-4) list the different items included in the substation rate base, with the total substation rate base in line 6. The substation rate base is multiplied by the pre-tax return rate in line 7 to arrive at the pre-tax return in dollars in line 8. Various expenses (lines 9 through 11) and revenue credits (line 12) are added to the pre-tax return to arrive at the total substation revenue requirement by Voltage in line 13. This total (in thousands of dollars) is divided by the maximum demand in MW (line 14) from Company witness Connolly to determine the SOC in line 15.

VI. ALLOCATION OF SURCHARGES

Q. Please describe Exhibit A-89 (EAD-5).

A. Exhibit A-89 (EAD-5) shows the allocation, by rate class, for the DR surcharge, the Electric Rate Case Deferral surcharge sponsored by Company witness Patrick M. Daly, and the IRM surcharge sponsored by Company witness Heidi J. Myers. Exhibit A-89 (EAD-5) is used by Company witness Connolly to calculate the surcharge rates.

Q. How is the Company proposing to allocate the Demand Response surcharge?

A. Demand Response costs have previously been allocated in the COSS using the production capacity allocator 220 (4CP 75/0/25). This treatment recognizes that DR is a capacity resource that is allocated in the same manner as other capacity costs. The Company is proposing to continue to allocate DR costs in this manner for the DR surcharge.

Q. How is the Company proposing to allocate the Electric Rate Case Deferral surcharge?

A. The Company is proposing to allocate the Electric Rate Case Deferral surcharge costs, which includes the cost of certain investment in the Company's distribution system, to each

1 class in proportion to their share of total distribution costs in this case. This is the same
2 method that has been used in previous cases.

3 **Q. How is the Company proposing to allocate the IRM surcharge?**

4 A. The Company is proposing to allocate the IRM surcharge costs, which includes the cost of
5 certain investment in the Company's distribution system, to each class in proportion to
6 their share of total distribution costs in this case. This is the same treatment that the
7 Company has used in previous cases for the IRM and Electric Rate Case Deferral
8 surcharges.

9 **VII. SUMMARY OF PROPOSALS**

10 **Q. Could you please summarize the Company's proposals in this case?**

11 A. Yes. The Company is requesting that the Commission approve the Company's Version 2
12 COSS which includes Company proposals to revise the allocation of: (i) Customer
13 Advances and (ii) OH line O&M Expenses. In addition, Consumers Energy requests that
14 the Commission approve the Company's proposed:

- 15 • Treatment of DCO project costs including the Company's proposal to no
16 longer require a breakout of the MAOAM project (formerly C&I Online
17 Account Management project) costs in future rate cases;
- 18 • SRM Capacity Charge;
- 19 • Substation Ownership Credit; and
- 20 • Allocation of surcharges including the Electric Rate Case Deferral, DR and
21 IRM surcharges.

22 **Q. Does this conclude your direct testimony in this proceeding?**

23 A. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

MATTHEW J. FOSTER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MATTHEW J. FOSTER
U-21870 DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

2 A. My name is Matthew J. Foster, and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am a Principal Rate Analyst for Consumers Energy Company (“Consumers Energy” or
6 the “Company”).

7 **Q. Please state your educational background.**

8 A. I graduated from Michigan State University with a Bachelor of Business Administration
9 with a major in finance.

10 **Q. What are your responsibilities in your current position?**

11 A. In my role as a Principal Rate Analyst, I am responsible for the development of Capital and
12 Operations & Maintenance (“O&M”) plan targets that align with rate case results.

13 **Q. Please describe your prior work experience.**

14 A. I have held my current position since April 2018. Prior to this role, I held various
15 accounting analyst roles within the finance organization, including in the General
16 Accounting and Property Accounting Departments. In these roles, I have been responsible
17 for property records, financial results, accounting entries, analysis, and reporting, including
18 Federal Energy Regulatory Commission (“FERC”) and Michigan Public Service
19 Commission (“MPSC” or the “Commission”) report filings.

20 **Q. Have you previously testified before the Commission?**

21 A. Yes. I testified in Case Nos. U-21224, U-21308, U-21389, U-21490, U-21585, and
22 U-21806 which include the Company’s most recent natural gas and electric general rate
23 cases.

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Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony is in four parts. In Part 1, I address the test year O&M expense for Corporate Services, including uncollectible expense and injuries and damages expense. In Part 2, I will address the test year capital expenditures for Corporate Services. In Part 3, I address technology projects that support the Corporate Services functions. In Part 4, I address the Company's requested accounting approval for the use of regulatory assets or regulatory liabilities, as needed, by the Service Restoration Resiliency Fund.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-90 (MJF-1)	Summary of Projected Electric & Common O&M Expense for the Years 2024, 2025, 2026 and the 12 Months Ending April 30, 2027;
Exhibit A-91 (MJF-2)	Electric Projected Corporate Services O&M Expense for the Years 2024, 2025, 2026 and the 12 Months Ending April 30, 2027;
Exhibit A-92 (MJF-3)	S&P Global Market Intelligence Ranking of Consumers Energy Electric A&G Costs for 2023;
Exhibit A-93 (MJF-4)	Electric Uncollectible Accounts Expense for the Years 2020 through 12 Months Ending April 30, 2027;
Exhibit A-94 (MJF-5)	Electric Injuries & Damages Expense for the Years 2020 through the 12 Months Ending April 30, 2027; and
Exhibit A-12 (MJF-6)	Schedule B-5.4 Electric Corporate Services Capital Expenditures for the Years 2024 through the 12 Months Ending April 30, 2027.

1 Q. Were these exhibits prepared by you or at your direction?

2 A. Yes, they were.

3 **PART 1 – ELECTRIC CORPORATE SERVICES O&M EXPENSE**

4 Q. Please describe Exhibit A-90 (MJF-1).

5 A. Exhibit A-90 (MJF-1) summarizes the Company's total 2024 through the 12 months ending
6 April 30, 2027 electric O&M expenses for Corporate Services, uncollectible accounts, and
7 injuries and damages. Column (a) of this exhibit provides the O&M expense category;
8 column (b) provides the source reference; column (c) provides the 2024 actual O&M
9 expense; column (d) provides the projected 2025 O&M expense; column (e) provides the
10 projected 2026 O&M expense; and column (f) provides the test year 12 months ending
11 April 30, 2027 O&M expense. These expense categories are discussed in detail below.

12 **Corporate Services O&M Expense**

13 Q. What areas are included within the Corporate Services O&M expense category, as
14 shown in Exhibit A-90 (MJF-1), line 1?

15 A. Corporate Services includes those areas common to the administrative functions of a
16 regulated corporation. These areas include Sustainability and External Affairs; Legal,
17 Ethics, Regulatory and Risk Management; People and Culture ("P&C"), Learning and
18 Development; Finance and Shared Services; General Activities; and Administration and
19 other costs.

20 Q. Please provide a brief overview of the various areas within the Corporate Services
21 area.

22 A. The areas within Corporate Services include:

- 23 • Sustainability & External Affairs – This area acts as a conduit between the
24 Company and its employees, customers, and external stakeholders. The group

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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 corporate strategy, strategic projects, 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

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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 financial 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 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 area. Corporate Safety includes operations safety, managing safety data, developing a safety strategy, and safety culture.
- 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 Edison Electric Institute dues, environmental minimum liability accruals, and intervenor funding.

Q. How are the 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, P&C are allocated based on either employee counts or labor, general costs are allocated based on the Three

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Factor Allocation Method, with other costs being directly charged for identified activities allocated based on capital and O&M spending levels or special studies.

Q. What is the Three Factor Allocation Method?

A. The Three Factor Allocation Method uses the average of operating revenue, labor, property, plant, and investments to allocate costs between the electric and natural gas businesses.

Q. Explain how the Adjusted Corporate Services O&M expense was calculated.

A. Exhibit A-91 (MJF-2), line 12, provides the Company's electric portion of total Corporate Services expenses, before exclusions. The 2024 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-91 (MJF-2), line 14, column (d), shows the total normalizations of one-time costs from 2024 total Corporate Services expense. One-time Consultant Expense were removed in the normalizations line. Total adjusted Corporate Services expense is found on line 15.

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 2.1% for 2025, 2.4% for 2026, and 2.4% for 2027. Consumers Energy uses these inflation rates to project Corporate Services O&M. Company witness Patrick D. Daly supports the inflation rates used.

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Q. In addition to increases related to inflation, what other specific line item changes are included to arrive at the test year O&M expense projection?

A. Exhibit A-91 (MJF-2), Column (m) includes a \$2,596,551 reduction to the projected test year for insurance distributions.

Q. Please describe in detail the specific line item change included in Exhibit A-91 (MJF-2), column (m), line 3 related to Insurance Distributions.

A. Exhibit A-91 (MJF-2), column (m), line 3, includes an adjustment of (\$2,596,551) for insurance distributions. This amount includes the removal of (\$6,369,342) for actual insurance distributions received in 2024 and was replaced with the five-year average for insurance distributions of (\$8,965,893). Below is a table showing the 2020 through 2024 historical amounts and the five-year average included in the projected test year.

Insurance Distributiouons (Refunds)	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	5-Year Average
NEIL	12,949,466	7,645,219	11,521,023	2,908,523	5,851,828	8,175,212
EIM	686,695	689,461	677,558	341,538	-	479,050
ICRP	47,554	47,863	48,145	48,393	60,932	50,577
AEGIS	177,405	227,014	223,125	221,143	456,582	261,054
Total	13,861,120	8,609,557	12,469,851	3,519,597	6,369,342	8,965,893

Q. Are the costs associated with restricted stock and the Employee Incentive Compensation Plan (“EICP”) included in the 2024 actuals or projected Corporate Services O&M expense?

A. No. Further details regarding restricted stock and EICP expenses are covered under the direct testimony of Company witness Amy M. Conrad.

Q. Is the level of test year Corporate Services O&M expense reasonable?

A. Yes. The reasonableness of the O&M expense level is supported by the fact that S&P Global Market Intelligence ranked Consumers Energy’s 2023 electric A&G costs

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(excluding pension and benefits) the third lowest out of 100 top companies ranked on a cost per customer basis for electric utility companies with more than 500,000 customers. The Company's ranking by S&P Global Market Intelligence in this regard is a strong indicator of the Company's diligence in managing overhead costs to help keep rates affordable for customers. Please refer to Exhibit A-92 (MJF-3) for the report on this ranking.

Q. What is S&P Global Market Intelligence?

A. The S&P Global Market Intelligence provides financial and operating data for electric utility companies.

Electric Uncollectible Expense

Q. How did the Company determine the uncollectible accounts expense included in the test year?

A. The Company projects the uncollectible accounts expense for the test year at \$20,273,798 as shown on Exhibit A-93 (MJF-4), 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 cash basis uncollectible accounts expense to electric service revenue for the years 2022 through 2024, as shown on Exhibit A-93 (MJF-4), page 2. This ratio is applied to the test year electric service revenue, plus surcharge revenue, to arrive at the sub-total of uncollectible accounts expense on Exhibit A-93 (MJF-4), page 2, line 9, column (e).

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1 **Q. Does the estimate of uncollectible accounts expense consider changing fuel and power**
2 **costs, their impact on customer bills, and the corresponding impact on uncollectible**
3 **accounts expense?**

4 A. Yes. By using the test year revenues multiplied by the three-year average BDLR, the latest
5 fuel and power cost projections are taken into account.

6 **Q. Does this method provide a reasonable estimate of uncollectible expense?**

7 A. Yes. The Company continuously strives to reduce uncollectible accounts expenses.
8 However, year-over-year, uncollectible accounts expense can be impacted by many factors.
9 The economy, the effectiveness of collection practices, funding of low-income assistance
10 programs, extreme weather fluctuations, or any number of other factors that could impact
11 a customer's ability to pay. As a result, the Company is proposing a three-year average
12 BDLR from 2022 through 2024 in this rate case filing. This method most effectively
13 captures the recent trends of the many factors that can impact uncollectible accounts
14 expenses.

15 **Electric Injuries and Damages Expense**

16 **Q. Please describe Exhibit A-94 (MJF-5).**

17 A. Exhibit A-94 (MJF-5) summarizes the Company's total 2020 through 2024 actual electric
18 injuries and damages expense and projected injuries and damages expenses through the
19 12 months ending April 30, 2027.

20 **Q. Please describe the costs related to injuries and damages.**

21 A. Electric injuries and damages include liabilities that arise in the normal course of Company
22 business for various types of items such as compensation for damaged trees and crops;
23 restoration of driveways, lawns, and fences; and accidents and lawsuits (up to a \$3,000,000

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insurance deductible per occurrence). 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 \$5,083,159 be included for the test year as shown on Exhibit A-94 (MJF-5), line 4, column (i).

Q. How was this amount determined?

A. Injuries and damages expense is comprised of three components: electric injuries and damages, internal legal costs, and workers' compensation costs. Exhibit A-94 (MJF-5), line 1, reflects the electric 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 are based on a five-year average of actual expense for the years 2020 through 2024.

PART 2 – ELECTRIC CORPORATE SERVICES CAPITAL EXPENDITURE

Q. Please describe Exhibit A-12 (MJF-6), Schedule B-5.4.

A. Exhibit A-12 (MJF-6), Schedule B-5.4, summarizes the Company's total 2024 through the 12 months ending April 30, 2027 electric capital expenditures for Corporate Services. Column (a) of this exhibit provides the program description; column (b) provides the 2024 actual capital; column (c) provides the projected 2025 capital; column (d) provides the projected 4 months ending April 30, 2026 capital; column (e) provides the projected 16 months ending April 30, 2026 capital; and column (f) provides the projected test year 12 months ending April 30, 2027. These categories include costs to equip and support

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Learning & Development and the Corporate Services areas primarily at Company headquarter locations with office furniture and equipment.

Q. Please explain how the projected Corporate Services Capital expenditures were calculated.

A. The 2024 actual capital expenditures were obtained from the Company's records and projected using non-labor 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 Stacey H. Baker includes, in his direct testimony and exhibits, three technology projects that are critically important in enabling the Company's Corporate Services functions to support the Electric business in a safe, effective, efficient, and compliant manner. Exhibit A-19 (SHB-3) contains the breakdown of Company spend for each project. These projects are described below:

- The **Enterprise Risk Management** project requires \$47,135 in O&M in the test year.

Description: 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.

Problem Statement: The Enterprise Risk Team ("ERT") works with Risk Owners ("RO") on an annual basis to identify new risks, update existing risks, quantify impacts and likelihoods of these risks, document mitigation plans, identify trends, and formulate risk tolerance metrics. This work is accomplished through an iterative back-and-forth process between ERT and ROs to gain alignment on content. This effort culminates in multiple Risk Map PowerPoint, Microsoft Word and email documents organized by area of risk. These risk maps are then presented to senior management and to the Board of Directors ("BoD") on an annual basis. The intensive, time-consuming manual Enterprise Risk Management 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

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analysts and risk owners throughout the Company, limits the breadth of analysis that can be provided, and limits the overall ability of the Company to timely identify, analyze, and communicate risks to our senior leaders, thereby causing potential delays in responding to emerging risks. Because of the lengthy manual process, it is only performed once a year, but must be performed more frequently to proactively manage enterprise risk. Utility industry peers leverage software to more effectively manage enterprise risk management programs.

Objectives: This project creates value for the Company by: (1) providing real-time risk information to interested parties including the risk team, risk owners, senior management, and the BoDs supporting proactive risk management; (2) creating a centralized repository for risk identification, management, and mitigation plans; (3) eliminating waste by simplifying processes; and (4) improving efficiency of the risk owners and analysts.

Scope: The scope of the project includes: (1) create risk analysis templates and tools for automated reporting; (2) configure automated workflow to perform risk updates; (3) configure dynamic templates that prompt the risk owners based on prior selections; (4) organize risk assessments through an online and searchable data capture (repository); (5) create new reports and executive dashboards; (6) data conversion; and (7) set record retention rules.

Alternatives: Alternatives considered include: (1) Continue use of the current manual processes which result in waste, lack of quality results, and annual review of risks; (2) Build a custom internal enterprise risk solution. This option was not selected as it will not result in an enterprise risk program that leverages best practices that exist in software provided by the leaders in risk management software; and (3) Implement a software solution from a leading enterprise risk solution vendor. While this would introduce new license and ongoing support costs, it is the preferred option because it leverages industry best practices with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation and insights via the reporting of risk information through management dashboards. In addition, it aligns the Company with utility industry peer practices for more effective enterprise risk management.

- The **2025 Union Contract Changes** project requires \$99,515 in O&M in the test year.

Description: The Human Resources - 2025 Union Changes project will implement SAP and other system changes required as a result of three collective bargaining agreements which will be renegotiated and ratified.

Problem Statement: Collective bargaining agreements expire every five years for Operating Maintenance and Construction (“OM&C”), Virtual Contact Center (“VCC”), and Zeeland employee groups. For OM&C, the current agreement ends June 1, 2025. The VCC agreement ends August 1, 2025. The

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Zeeland agreement ends October 1, 2025. Collective bargaining agreements expire every five years for OM&C, Customer Contact Center (“CCC”) and Zeeland employee groups. For OM&C, the current agreement ends June 1, 2025. CCC agreement ends on August 1, 2025. Zeeland agreement ends October 1, 2025. Technology changes are required to reflect these new agreements. Otherwise, employees in these union groups may not be paid appropriately or get correct benefits.

Objectives: Completion of this project will provide value to the Company and its customers through: (1) waste elimination by making changes in the software for any pay and benefit changes as required by the new agreements; (2) defect reduction by adding process automation to otherwise manual processes for tracking and recording work, premium, and absence time; and (3) improved employee engagement among the OM&C, CCC, and Zeeland union employees.

Scope: The scope of this project encompasses making any system changes required to support the new working agreement for the OM&C, CCC, and Zeeland employees. Exact details will be finalized after the negotiation process is completed and contracts are approved.

Alternatives: Three alternatives were considered for this project: (1) Make no system changes after the contracts are ratified. This option was not chosen because it exposes the Company to possible fines, disengaged employees, union grievances, significant manual processes leading to greater possibility of error, hiring additional staff to perform activities outlined in the agreements, and increased legal costs due to employee grievances; (2) Find other third-party software to support the changes required by the union agreements. This option was not chosen because it would require SAP integration along with additional software licensing and maintenance costs; and (3) Make system changes to eliminate manual updating, comply with the working agreement language, support union employee engagement, and reduce grievances. Option (3) was chosen because it leverages current SAP technology, automates what would otherwise require manual processing, and is the least costly option.

- The **Self Service Vendor Portal** project requires \$61,629 (\$49,303 Rough Order of Magnitude (“ROM”) Adjusted Capital) in capital and \$77,930 in O&M in the test year.

Description: The work will create an external portal for vendors to exercise self-service features to streamline and automate purchase order (“PO”) and invoice management and improve visibility to invoice and payment status.

Problem Statement: For Accounts Payable, vendors must repeatedly interact with the Company through multiple channels to ask questions, submit invoices, or check invoice or payment status, including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates, to make payments, or to respond to

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missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for vendor invoice and payment management and lacks the ability for vendors to utilize touchless invoice creation from POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes six contracted resources, and creates the potential for late payments or missing early payment discounts. For Supply Chain, vendors must repeatedly interact with the Company through multiple channels to ask questions, update POs (quantities, costs, shipping dates) including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for updates to the POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes four employee resources. This also creates the potential for late payments, missing early payment discounts, delays in receiving due to lack of shipping notifications from vendors, delays to scheduled work due to lack of acknowledgement and lead time adherence, and the inability to enforce contractual obligations.

Objectives: This project creates value for the Company by: (1) creating self-service functionality/increasing touchless invoice creation/processing that allows the vendor to select items from a PO to create an invoice on demand; (2) providing vendors with real-time invoice and payment status, increasing employee productivity by eliminating waste; (3) allow self-service updates of vendor master data (banking info, remittance info, etc.) (4) fewer late payments by vendors thus reducing Company follow up and tracking; (5) creating better visibility for vendors to take advantage of early payment discounts thus reducing related vendor inquiries; (6) reducing vendor questions related to invoice and POs through self-service functions and portal information; (7) reducing the cost per invoice; (8) creating self-service functionality/increasing touchless PO creation/processing that allows the vendor to select items from a PO to update quantities, costs, and shipping dates; (9) providing vendors with real-time PO information, increasing employee productivity by eliminating waste; and (10) fewer late deliveries by vendors thus reducing Company follow up and tracking.

Scope: The project scope includes: (1) submit an request for proposal for a vendor portal solution and implementation; (2) configure ability for vendors to more efficiently and more accurately self-submit invoices and POs electronically; (3) configure ability for vendors to self-convert items on a PO to an invoice; (4) configure ability for vendors to view invoice and payment status; (5) configure ability for vendors to make changes to SAP master data, including PO line item details; (6) configure ability to offer/process dynamic discounting (7) create new reports and dashboards; (8) enabling method to validate vendors should have access to the portal and removing access when appropriate;

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(9) configure ability for vendors to make self-serve changes to shipping status and delivery dates; and (10) integration to vendor invoice management system and SAP.

Alternatives: Alternatives considered include: (1) Continue use of the current manual processes which results in waste and inefficiencies for employees and vendors. This could also result in late payments and lost discounts for vendors; and (2) Build a custom solution. This option was not selected as the Company has a vendor portal, that is only leveraged for vendors to ask questions. As well, it doesn't leverage best practices; (3) Building a combination of custom and standard integration to existing solutions. This option was not selected because it doesn't follow industry best practices; (4) expand our current vendor portal. This option was not chosen due to limited functionality and not matching capability roadmaps; and (5) implement a new SaaS solution specific to a vendor portal experience. Option (5) is the preferred option because it leverages industry best practices with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation to vendors via real-time processing.

PART 4 – ACCOUNTING REQUESTS

Service Restoration Resiliency Fund

Q. Company witness Andrew R. Snider recommends the adoption of the Service Restoration Resiliency Fund for service restoration O&M expense. Please summarize the mechanism and describe the determination of the amount reserved.

A. The Service Restoration Resiliency Fund would allow the Company to record a regulatory liability when the actual projected test year expense is lower than the rate case authorized service restoration O&M. The regulatory liability would act as a reserve to support service restoration expenses in future years when actual O&M is exceeding the rate case authorized O&M. The Fund is capped at \$30.7 million to ensure that the fund only preserves the dollars needed to respond to a potential catastrophic event, after which customers would see a financial benefit from the Company's efficiency. The cap limit was based on the average O&M costs for a catastrophic storm for the past three historic years (2022, 2023

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1 and 2024). The average storm cost was then adjusted for inflation based on the 2.4%
2 inflation rate supported by Company witness Daly as part of this case.

3 **Q. Please describe how the Company would treat underspent dollars that cause the**
4 **regulatory liability to exceed the cap of \$30.7 million.**

5 A. The Company would propose a refund method in its next electric rate case.

6 **Extraordinary Storm Accounting**

7 **Q. Company witness Snider makes a proposal for Extraordinary Storm Accounting**
8 **(“ESA”). Please summarize this mechanism.**

9 A. The ESA would allow for deferred accounting treatment for service restoration costs for
10 severe storms once actual service restoration costs exceed amounts included in rates and
11 any service restoration resiliency fund has been depleted. Storms that would qualify for
12 deferral under this proposal are storms that cause at least 300,000 customer outages
13 (16.6% of Consumers Energy customers) or storms that result in a State of Emergency
14 declaration from the Governor’s office.

15 **Q. Please describe how the Company would treat any amounts deferred under this**
16 **mechanism.**

17 A. These amounts would be recorded to a regulatory asset and the Company would support
18 the deferred amounts for recovery in its next electric rate case.

19 **Q. Does this conclude your direct testimony?**

20 A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

ALEX M. GAST

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

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1 **Q. Please state your name and business address.**

2 A. My name is Alex M. Gast, and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

4 **Q. What is your position with Consumers Energy Company (“Consumers Energy” or**
5 **the “Company”)?**

6 A. I am the Manager of Customer Regulatory Strategy in the Customer Experience
7 department.

8 **Q. Please state your educational background and work experience.**

9 A. In 2011, I graduated from Central Michigan University with a Bachelor of Science degree
10 in Business Administration, with a major in accounting. In 2013, I graduated from Spring
11 Arbor University with a Master of Arts degree in Business Administration. I am also a
12 Certified Public Accountant registered in the state of Michigan.

13 From 2012 to 2014, I was employed by Plante & Moran as a Staff Auditor. My
14 responsibilities included the planning and execution of financial statement audits, reviews,
15 and consulting engagements for a variety of non-profit, healthcare, and manufacturing
16 clients.

17 In 2014, I joined Consumers Energy as a Business Support Advisor in the
18 Distribution, Operations, Engineering, and Transmission department. My responsibilities
19 included managing financial budgets, forecasts, and long-term financial plans for natural
20 gas and electric programs. In 2015, I joined the Energy Resources department as a
21 Financial Analyst where I worked on business plans and performance metrics and was
22 promoted to the lead of that team in 2016. In 2018, I joined the Pricing section of the Rates
23 and Regulation department, and my responsibilities included cost of service studies, rate

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design, research and development of additional services, analyses for Senior Management, and customer-specific rate analyses. In 2023, I joined the Customer Experience department as a Principal Rate Analyst and was promoted to Manager of Customer Regulatory Strategy in 2025. I am responsible for regulatory strategy and filings related to the Company's clean energy plan, including Demand Response ("DR") and Energy Waste Reduction ("EWR").

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-20365	2018 EWR Reconciliation;
Case No. U-20372	2020-2023 EWR Plan;
Case No. U-20650	General Gas Rate Case;
Case No. U-20702	2019 EWR Reconciliation;
Case No. U-20865	2020 EWR Reconciliation;
Case No. U-20875	2022-2025 EWR Plan;
Case No. U-20893	Investment Recovery Mechanism Reconciliation;
Case No. U-21148	General Gas Rate Case;
Case No. U-21389	General Electric Rate Case;
Case No. U-21647	2023 DR Reconciliation; and
Case No. U-21906	2024 DR Reconciliation.

Q. What is the purpose of your direct testimony in this case?

A. The purpose of my direct testimony is to describe the Company's DR program, associated costs, and proposed updates. As part of my direct testimony, I will address: (i) the DR

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operating and maintenance (“O&M”) expenses and capital investments in the test year ending April 2027.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-12 (AMG-1)	Schedule B-5.5	Actual and Projected Capital Expenditures – Demand Response;

Exhibit A-95 (AMG-2)		Summary of Actual & Projected O&M Expenses – Demand Response; and

Exhibit A-182 (AMG-3)		Whole Home Optimization Demand Response pilot.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please describe the exhibits you are sponsoring.

A. Exhibit A-12 (AMG-1), Schedule B-5.5, details the capital expenditures related to DR in the historical year, bridge period, and projected in the test year. Exhibit A-95 (AMG-2), page 1, details the O&M expenses related to DR in the historical year and projected in the test year. Exhibit A-95 (AMG-2), page 2, includes projections for DR O&M based on inflation. This page is not intended to represent how the Company has developed its projected DR O&M. Column (b) shows the historical O&M expense. Column (c) shows the historical amount to which an inflation rate or merit increase rate was applied. Columns (e) and (g) show the amounts to which a hypothetical inflation rate or merit increase rate were applied for each bridge period, respectively. Columns (d), (f), and (h) show the hypothetical merit and inflation increases for each respective period. Because the Company does not develop the projected DR O&M using inflation it is necessary to include column (i), other adjustments. Column (i) is simply the difference between the Company’s

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1 actual projected O&M and what the O&M would have been if the Company had used
2 inflation to project DR O&M. Column (j) is the projected test year O&M and is the sum of
3 columns (b), (d), (f), (h), and (i). The expenses supported here are based upon the expenses
4 necessary to meet the needs of DR program planned in the test year and are not based on
5 applying an inflation rate to the historical O&M expenses.

6 **Q. Please explain the DR programs offered by the Company.**

7 A. The Company offers a DR portfolio comprising of both residential and business DR
8 programs. The portfolio consists of three residential programs: Device Cycling, Dynamic
9 Peak Pricing (“DPP”), Residential Smart Thermostat; and two business programs:
10 Commercial and Industrial (“C&I”) Contractual DR, and C&I Rate options.

- 11 • Residential Device Cycling involves installing direct load control switches on
12 high energy use equipment at customer homes. These switches are capable of
13 receiving DR event signals that turn off connected loads for a specified amount
14 of time during events. At the end of 2024, the program had over 95,000
15 participants and represents 57.3 MW of enrolled capacity.
- 16 • Residential DPP offers customers pricing options that are designed to
17 incentivize reduced energy use during peak hours. At the end of 2024, the
18 program had over 176,000 participants and represents 37.9 MW of enrolled
19 capacity.
- 20 • The Residential Smart Thermostat Program uses cloud-based software
21 deployed through the customer’s Wi-Fi thermostat to optimize energy savings.
22 As of 2024, the program had nearly 59,000 participants and represents
23 54.2 MW of enrolled capacity.
- 24 • The Business DR Contractual Program offers payment based on contractual
25 agreement to reduce load by a contract amount during Midcontinent
26 Independent System Operator, Inc. (“MISO”) emergencies during all MISO
27 seasons. The Business DR Contractual Program has set event, duration, and
28 timeframe limits specified in the agreement. As of 2024, the program included
29 1,402 accounts and 249 MW of enrolled capacity.
- 30 • Business DR Rate Options includes the General Interruptible (“GI”) and
31 General Interruptible 2 (“GI2”) rate provisions, Rate Energy Intensive Primary
32 (“EIP”), and Long-Term Industrial Load Retention Rate (“LTILRR”) which
33 provide discounts, monthly on-bill incentives, market pricing signals, or a

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combination of these to C&I customers for reducing load during emergencies year-round. Each option does include specific criteria for entry. As of 2024, Business DR Rate programs had an approximate enrollment of 39 accounts and 259.5 MWs of enrolled capacity.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

I. COST DETAILS

II. SURCHARGE & REGULATORY FRAMEWORK

III. RESIDENTIAL DR

IV. BUSINESS DR

V. NEW DR PILOT

VI. SUMMARY

I. COST DETAILS

Q. Please explain the O&M costs associated with the DR programs offered by the Company.

A. Projected O&M costs for the test year for these programs are \$34.6 million and are included on Exhibit A-95 (AMG-2), page 1. Capital costs for these programs are projected to be \$1.56 million in the test year and are included in Exhibit A-12 (AMG-1), Schedule B-5.5. These programs are designed as a lower-cost, flexible capacity resource that can be used during times of peak electricity demand to mitigate system constraints and, ultimately, to reduce costs paid by customers. This capital and O&M spending are related to enrolling (or “activating”) customers interested in participating in DR and implementing DR programs.

Costs related to the DR Program are broken into three major categories – labor, contractor costs, and non-labor other.

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- 1 • *Labor* spending related to DR programs is associated with internal labor
2 resources that support the program through event operations, program
3 management, marketing, data visualization & analytics, customer research,
4 evaluation, and contractor support. These activities are critical in the
5 deployment of voluntary DR programs as they require a different value
6 proposition and resourcing than traditional electric utility service to bring to
7 market and promote customer participation.
- 8 • *Contractor costs* are allocated to the three major contractors that Consumers
9 Energy works with in the management of these DR programs – EnergyHub,
10 Honeywell, and Enel X. These costs cover activities such as: managing
11 thermostats for the Smart Thermostat Program, C&I customer portals used to
12 dispatch event notification, incentives, installation fees for switches,
13 thermostats, and the functional marketing costs related to digital, social,
14 mailings, etc. Most of these contractor costs closely align with the number of
15 customer enrollments and as enrollments continue to increase in conjunction
16 with the Company’s integrated resource plan (“IRP”) plan, the Company will
17 continue to see increased costs in these spaces related to incentives as it seeks
18 to enroll new and retain existing customers in the face of audience saturation
19 and looming requirements from MISO’s DR reform. The Company also
20 anticipates higher contractor Software as a Service (“SAAS”) fees to manage
21 these devices with the latest software upgrades. The Company’s contracts with
22 these contractors have financial and performance metrics included to ensure
23 that Consumers Energy is achieving cost effectiveness.
- 24 • *Non-labor costs* are additional costs incidental to the program but not directly
25 related to labor costs, for C&I programs most customer incentives are included
26 in non-labor costs. When looking at capital costs for DR programs, the major
27 contributor to cost is materials. For the residential program, the Company
28 works with contractors for the installation of device cycling switches. For the
29 majority of Business DR customer communications, equipment is installed to
30 allow for dispatch communications during events and provide customers with
31 the necessary tools to perform during events. The remaining customers receive
32 communications that are manually triggered by CE employees.

33 **Q. What benefit does the Company’s DR Program provide?**

34 A. Electric demand varies by season and the Company must secure sufficient capacity
35 resources for any time of peak demand (plus a reserve margin). As a result, some generation
36 resources are rarely fully utilized outside of high-demand summer months. DR programs
37 help manage capacity need for peak demand, in lieu of additional supply-side electric
38 generation or capacity contracts. Ultimately, the Company’s DR programs help balance

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Michigan's electricity needs to help protect the grid, react to emergencies and severe weather, and avoid the cost of additional generation infrastructure to serve peaks. Further, as discussed by Company witness Megan L. Metz, customers will receive \$62 million worth of capacity value in Planning Year 2025/2026 from the MWs, or the Zonal Resource Credits, that the DR programs provide.

DR also provides the opportunity for customers to take better control of their energy usage, decrease their energy costs, and participate in the Company's Clean Energy Plan. Residential customers benefit from participating in DR programs by saving money when they shift flexible demand to hours when energy is less expensive. All customers benefit from DR reducing grid strain during peak demand periods because reducing grid strain offsets the Company's need to invest in more generation or capacity resources.

Most importantly, demand-side resources such as DR are essential to meeting climate goals and achieving the MWs approved in the IRP. The DR Program remains essential to the Company's long-term ability to achieve greater flexibility and improved sustainability over the long term.

Q. What is the Company's overall approach to DR in the future?

A. The Company has taken efforts to reduce costs and increase MWs while working to develop strategies in response to the evolving nature of DR in Michigan. The Company is focusing on programs with the greatest cost effectiveness, such as C&I programs and the Smart Thermostat Program. In addition, the Company seeks to innovate in DR and a new pilot proposal is discussed below, the pilot takes advantage of new technologies and is expected to yield useful information as the Company seeks to expand DR opportunities in the most cost-effective ways.

II. SURCHARGE & RECONCILIATION PROCESS

Q. Is the Company requesting approval of a DR surcharge in this case?

A. Yes. Consistent with the Order in Case No. U-21585, the Company has calculated a separate revenue requirement for the DR Program inclusive of all DR related capital, O&M costs, and rate credits. The DR revenue requirement is supported by Company witness Patrick D. Daly in Exhibit A-83 (PDD-59). These costs, along with the DR related credits in the Company's rate design, are included in the proposed DR surcharge supported by Company witness Laura M. Connolly in Exhibit A-16 (LMC-2), Schedule F-2.1. The DR surcharge will be adjusted during the Company's annual DR Reconciliation proceedings to account for changing costs, over/under-recoveries, and recovery of the performance incentive. During the annual reconciliation, the Company will use the same DR surcharge methodology approved by the Commission in the last approved rate case, Case No. U-21585.

Q. How will the surcharge be calculated and implemented?

A. The Company's DR reconciliation surcharge calculation methodology is supported by Company witness Connolly. The Company used the calculation methodology in the ongoing DR reconciliation proceeding, Case No. U-21906, to request surcharges to refund any overcollections, collect any under-recoveries, and for recovery of DR performance incentives. Company witness Emily A. Davis is supporting the allocation of the revenue requirement by rate class.

Q. Is the Company requesting any other changes?

A. Yes. The Company proposes that DR capital and O&M spend be considered as a part of the annual DR plan and reconciliation instead of as a part of any general rate case. The

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Company proposes that, each annual DR reconciliation filing operate as both a DR plan and a DR reconciliation.

The Company has presented DR capital and O&M spend in this case as it has traditionally done, if this proposal to change the DR regulatory construct is not approved. In the annual reconciliation, the Company proposes to reconcile DR spend and incentive, while also requesting approval for spending in the subsequent year. This modification aims to further mitigate regulatory lag and reduce the complexity associated with DR in multiple cases, as illustrated by Table 1 below.

Table 1

Plan & Reconciliation Structure			Electric Rate Case Approving DR Spend			
DR Program Calendar Year	Year Reconciled	Year Surcharge Implemented	U-21389 (2023)	U-21585 (2024)	U-21870 (2025)	2026 Case
2025	2024	2026	Jan-Mar	Apr-Dec		
2026	2025	2027		Jan-Apr	May-Dec	
2027	2026	2028			Jan-Apr	May-Dec

1 **Q. Has the Company proposed this change in other filings?**

2 A. Yes. The Company has also proposed this change in its 2024 DR reconciliation, Case No.
3 U-21906.

4 **Q. When does the Company propose the new structure take effect?**

5 A. The Company requests that the change take place with the 2025 DR reconciliation, which
6 would be filed in 2026 to reconcile 2025 spending and propose new spending for 2027.

7 **Q. Has DR capital and O&M been included in the present case?**

8 A. Yes. The Company has presented DR capital and O&M spend here as it has traditionally
9 done and has included DR O&M and Capital spend for the test year which includes a
10 portion of 2026 and 2027.

11 Consequently, the requested change, prorated with what was already approved for
12 a portion of 2026 in the Company's previous electric rate case (Case No. U-21585), would
13 make up the 2026 ask that, if approved, would allow the Company to remove DR from the
14 rate case, except for credits that will remain included in the rate design (reference Table 1).

15 **III. RESIDENTIAL DR**

16 **Q. Please explain the structure of the Residential DR Program.**

17 A. The Company offers three Commission-approved Residential DR programs: a Device
18 Cycling program, a DPP program, and a Smart Thermostat program.

19 **Q. Is the Company proposing any changes to the Residential DR portfolio?**

20 A. Yes, the Company is proposing changes to the DPP program as discussed below. The
21 Company is not proposing changes to the Device Cycling program credit that was recently
22 updated to \$5 per customer-month in June through August because of the Order in Case
23 No. U-21585. The latest value of MISO's Cost of New Entry ("CONE") is \$130,930/MW-

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year in Zone 7, which is only 3% higher than the prior year and results in no change to the Device Cycling credit calculation approved in the previous rate case.

Q. Please describe the residential Device Cycling Program and the related customer benefits.

A. In the Device Cycling Program, the Company installs direct load control switches on air conditioning (“AC”) units. The program ended in 2024 with 57.335 MW of capacity – the largest contributor to the residential portfolio. When the Company activates a switch, it will cycle the output of the connected load by between 40% and 75%. At the end of an event, each system returns to normal operation. In exchange, customers receive a monthly bill credit of \$5 during the billing months of June through August, as recently approved in the Company’s prior electric rate case, Case No. U-21585. Customers previously received a \$25 enrollment incentive, but the Company discontinued this when the program was moved into maintenance mode. In months with events, customers reduce load during peak hours which can translate into a shift in kWh from the peak to off-peak period, lowering bills.

Q. Please describe the residential Smart Thermostat Program.

A. The Smart Thermostat Program is for customers who have central AC, and a participating Wi-Fi-enabled smart thermostat and agree to participate in DR events. During a DR event, customers can expect their thermostat setpoint to adjust up to 4 degrees above their current setpoint to reduce strain on the electric grid during high demand days, in the summer months of June - August. The program uses cloud-based software deployed through the customer’s Wi-Fi thermostat to perform a pre-emptive energy optimization (pre-cooling) of the home to achieve greater demand savings during the duration of the DR event.

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1 **Q. Please describe the direct benefits customers receive for participating in the Smart**
2 **Thermostat Program.**

3 A. Customers participating in the Smart Thermostat Program receive an incentive for signing
4 up in the program. If the customer already has a participating (Google Nest, Ecobee,
5 Honeywell, Emerson, Alarm.com, or Amazon smart thermostat) device, the customer will
6 sign up through the Bring Your Own Device (“BYOD”) path and receive a Pre-Paid
7 Mastercard as an enrollment incentive. If the customer does not already have a
8 participating Smart Thermostat, they can purchase a thermostat through the Consumers
9 Energy Residential Online Store and receive an instant incentive credit toward the purchase
10 of the new DR Pre-Enrolled (“DRPE”) Smart Thermostat. Both paths currently receive an
11 annual Pre-Paid Mastercard at the end of event season for participation in the program.

12 **Q. Please describe the Company’s plans to expand the Smart Thermostat Program.**

13 A. The Smart Thermostat Program has expanded from 1,939 participating customers in 2019
14 to over 58,000 cumulative customers in 2024. This plan accounts for almost 68,500
15 customers in the Smart Thermostat Program by the end of 2025 totaling over 63 MWs.
16 The Company added two new thermostat options (Alarm.com and Amazon smart
17 thermostat) in 2024 for the BYOD flow. This will continue to foster a seamless customer
18 enrollment path and a DR solution for all Consumers Energy customers. Also, for the Smart
19 Thermostat Program, the Company will roll out an offline device management effort in
20 2025. This initiative will help the Company more easily identify when a thermostat is not
21 connected to Wi-Fi and controllable for at least 90 days or more. The Company will work
22 with EnergyHub to send a series of emails to the offline device participants, as an effort to
23 get the device reconnected and controllable again. After a series of email attempts to

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1 reconnect, the Company will de-enroll participants that took no action to reconnect. This
2 effort supports the Company's cost-effectiveness goals and could increase the program's
3 overall kW/device savings during called DR events and thereby allowing the Company to
4 register a higher percentage of enrolled MW with MISO as a Load Modifying Resource,
5 providing capacity value.

6 **Q. Please describe the residential DPP Program.**

7 A. The Company's DPP Program is designed to encourage customers to shift their energy
8 consumption away from the hours of a DR event. Currently, the Company offers two
9 pricing options under the program, Critical Peak Pricing ("CPP") and Peak Time Rewards
10 ("PTR"). The goals of the two pricing options are identical, but the approach to achieve
11 them differs. The CPP option charges customers a significantly higher rate of \$1/kWh of
12 energy used during DR event hours. In exchange, customers are offered a discount on their
13 rate during weekends, holidays, and all hours of the weekdays except 2 p.m. to 7 p.m. The
14 CPP Program is generally referred to as a "stick" incentive - using strong pricing signals
15 to reduce consumption during an event. Alternatively, the PTR option offers customers a
16 payment for reducing their energy during DR events. This is currently a credit of \$1/kWh
17 of energy reduced during event hours as compared to their baseline use.

18 **Q. Is the Company proposing any changes to the DPP program for the test year?**

19 A. Yes. The Company is proposing to reduce the per customer demand savings for PTR
20 from 0.21 kW/customer to 0.13 kW/customer and for CPP from 0.25 kW/customer to
21 0.18 kW/customer. The Company is also proposing to reduce the PTR credit, currently at
22 \$1/kWh of energy reduced during event hours to \$0.50/kWh.

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1 **Q. Why is the Company proposing to make changes to the DPP program demand savings**
2 **values and the PTR credit?**

3 A. The Company, working with its third-party evaluator Cadmus, predicted a lower capability
4 than the 2022 planning value previously being used. With this lower value being nearly
5 half the previous value for PTR, the Company determined that the credit offered to these
6 customers should also be halved.

7 **Q. Please describe the importance of PTR as a part of DPP and the Residential DR**
8 **Portfolio.**

9 A. The PTR Program is a critical component to the Company's overall residential DR
10 portfolio because it provides customers a no-risk option to participate in DR. From a
11 portfolio standpoint, the Company has seen a higher enrollment rate for PTR compared to
12 other DR offerings with 153,147 cumulative enrollments in 2024. DPP also has the highest
13 rate of Low-Income enrollments. Although the enrollment rate for PTR is higher, the per
14 customer demand savings are significantly lower than the rest of the portfolio (at
15 0.21 kW/customer, currently, and proposing to reduce further to 0.13 kW/customer) vs
16 0.92 kW per customer for the Smart Thermostat Program. The combination of a high
17 conversion rate paired with low demand savings has influenced the Company's strategy to
18 view PTR as an "entry-level" or "gateway" offering. Meaning, the Company plans to
19 leverage the willingness of customers to participate in PTR to get them familiar with DR
20 in a no-risk way before encouraging them to participate in a different program (primarily
21 the Smart Thermostat Program) where demand savings to the customer and the Company
22 are more predictable and controllable. Given the change in strategy to use PTR as a
23 gateway DR program, the Company has made significant changes to reduce expenses for

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1 the program to improve cost-effectiveness. The Company is: (1) working on
2 the discontinuation of customer enrollment incentives, and (2) focusing primarily on low
3 to no cost marketing channels including the Consumers Energy website during the time of
4 move-in.

5 While PTR is not actively registered in-market, the Company continues to promote
6 enrollments in the program that is best suited for each customer. The Company worked
7 with over 2,328 customers to upsell them from PTR to the Smart Thermostat Program
8 during 2024. The focus of this upsell is to promote customers to join a more cost-effective
9 DR program while earning a higher incentive.

10 **IV. BUSINESS DR**

11 **Q. Please explain the structure of the Business Contractual DR Program.**

12 A. Each business customer that signs up for the Business DR Contractual Program is
13 contracted for a specified load (kW) reduction. The Company works with individual
14 business customers to set up a demand reduction plan at their facility that will be
15 implemented when a DR event is called. Business customers of different sizes participate
16 through this process to create a business DR portfolio. When MISO expects the grid to be
17 strained because of high electric demand or during periods of high market costs, the
18 Company notifies participants within the Business DR Program of the need to reduce load.
19 Customers then have 30 minutes to execute their curtailment plan (unless the event is
20 scheduled at a specific future time). The resulting reduction in peak load is for the purpose
21 of relieving stress on the electric system in a more cost-effective manner than purchasing
22 capacity from the market or building additional generation resources.

1 **Q. How does the Business DR Contractual Program differ from the Company's**
2 **interruptible rates?**

3 A. The Company's interruptible rate defines specific capacity and energy billing parameters,
4 whereas the Company's Business DR Program provides a contract with customers to
5 defining specific program parameters. With the interruptible rate options customers are
6 charged a lower rate in exchange for a firm commitment to reduce demand by or to a
7 specified amount during MISO events. Participants who choose to deviate from this
8 commitment during MISO events are assessed a significant financial penalty or are subject
9 to higher real time market prices depending on rate or provision.

10 The Business DR Contractual Program also comprises demand curtailment
11 commitments. But unlike the Company's interruptible rate options, customers choose to
12 nominate an amount of demand they are willing to reduce during events at specific
13 timeframes and dates for the program year. The contractual program has limits on the
14 number of events, duration of events, and days in which events can be called. Customers
15 receive payments for their performance during MISO Emergency Events for up to 250%
16 of their nominated amount. The financial benefit to participating business customers is
17 less significant with the Business DR Contractual Program than with the interruptible rate
18 options, to recognize the reduced event risk timeframes and durations customers are
19 exposed to.

20 **Q. How are participants compensated for reducing their electric load during peak**
21 **demand events?**

22 A. Participants are compensated for capacity and energy reductions during events. The
23 capacity payment is tied to kW of reduction nominated, and the energy payment is based

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1 on kWh reduction during events. Both are measured from an established baseline in
2 accordance with MISO calculations. Compensation for capacity is based on the customer's
3 contracted capacity reduction during the program enrollment period. The customer
4 receives payment for energy based on performance during events. Incentive payments are
5 priced for market competitiveness and are a component of the overall cost of having and
6 managing a DR capacity resource. Average nomination in Business DR is 178.8 kW and
7 historical average capacity incentive equates to \$4,774. These results will vary based on a
8 customer's actual performance for given events.

9 **Q. Do non-participating customers benefit from the Company offering a Business DR**
10 **program?**

11 A. Yes. The Company's Business DR Program provides a flexible, repeatable, and scalable
12 capacity resource. The program benefits all Consumers Energy customers by reducing the
13 need to purchase additional capacity during times of peak demand, thereby reducing the
14 cost of providing power to all customers.

15 **Q. Will these DR contracts be bid into MISO?**

16 A. Yes. The Company will bid into MISO based on the portfolio capacity of participating
17 customers. Each participating customer will be required to enter a contract with the
18 Company, which outlines the terms of performance in keeping with MISO requirements
19 for a Load Modifying Resource and payments as it relates to the contracted capacity and
20 energy. Capacity payments are standardized at the same rate for all participating
21 customers.

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1 **Q. Is the Company proposing other tariff-related changes for Business DR?**

2 A. No. The Company is not proposing changes to the GI provision credits that were recently
3 updated to \$8.50/kW-month in summer months and \$7.70/kW-month in non-summer
4 months as a result of the Order in Case No. U-21585. The latest value of MISO's CONE
5 is \$130,930/MW-year in Zone 7, which is only 3% higher than the prior year and results
6 in no change to the GI credit calculation approved in the previous rate case.

7 **Q. Is the Company enhancing existing elements of the Business DR Contractual**
8 **Program or developing new offerings?**

9 A. Yes, the Company has transitioned the Business DR Contractual Program to a seasonal
10 structure and will launch its first year-round season on June 1, 2025. Early results from this
11 new approach have been encouraging, with seasonal contracts demonstrating improved
12 participation and customer engagement. The Company anticipates continued growth in
13 registered megawatts each season as it refines and optimizes the program. The Business
14 DR Contractual Program will also continue to explore different payment structures that are
15 more performance and event based. The flexibility built into the contractual framework
16 allows the Company to provide timely program upgrades and adapt to evolving customer
17 market needs.

18 **V. NEW DR PILOT**

19 **Q. Is the Company requesting funding for any DR Programs?**

20 A. Yes. The Company is seeking \$750,000 capital and \$250,000 O&M included in Exhibit
21 A-12 (AMG-1), Schedule B-5.5 and Exhibit A-95 (AMG-2), respectively for its proposed
22 Whole Home Optimization Demand Response pilot, that will test customer-owned smart
23 home energy management systems, battery storage, and load management devices. The

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costs associated with testing these technologies include technology demonstrations for the various customer types. Load Management Devices will require an investment of \$200,000, multifamily whole unit optimization will require \$200,000, single-family whole home optimization will require \$150,000, and smart analytics and aggregation through whole home smart optimization will require \$200,000. Additionally, evaluation, incubation, and labor costs are estimated at \$250,000.

Q. Please describe the proposed pilot.

A. The Company's proposed Whole Home Optimization Demand Response pilot will allow the Company to test how customers respond to and interact with energy usage and demand analytics, customer-controlled responses and behavior, and aggregation of resources within their home using a whole home optimization approach.

The Company is seeking to test this technology specifically with its residential customers given the past implementation of Time-of-Use ("TOU") rate structures (RSP 1001, RSH 1040, and RPM 1050), to quantify energy savings impacts, and to understand the barriers customers face with adopting DERs in the home, including battery storage and electric vehicles, to shift energy off-peak.

The Company will work with implementation contractors, third-party evaluators, and software and hardware vendors to install and test a variety of available technologies to assess cost-effectiveness, demand reduction, energy waste reduction, customer interest, and technical integration feasibility.

The pilot is discussed in detail in Exhibit A-182 (AMG-3).

1 **VI. SUMMARY**

2 **Q. Please summarize your direct testimony.**

3 A. The Company projects \$34.63 million in O&M expenses in the test year and \$1.56 million
4 in capital in the test year to support DR programs, including the pilot proposal. Details on
5 the DR revenue requirement are supported by Company witness Daly and details on the
6 DR surcharge are supported by Company witness Connolly.

7 **Q. Does this conclude your direct testimony?**

8 A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-21870
the generation and distribution of	)	
electricity and for other relief.	)	
_____	)	

DIRECT TESTIMONY
OF
BRITTANI A. GRAY
ON BEHALF OF
CONSUMERS ENERGY COMPANY

BRITTANI A. GRAY
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1 **Q. Please state your name and business address.**

2 A. My name is Brittani A. Gray, and my business address is One Energy Plaza, Jackson,
3 Michigan, 49201.

4 **QUALIFICATIONS**

5 **Q. By whom are you employed and in what capacity?**

6 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
7 as a Senior Tariff Analyst in the Rates and Regulation Department.

8 **Q. Please describe your educational and professional experience.**

9 A. In January 2010, I was hired by Consumers Energy as a Customer Service Representative
10 within the Company’s Customer Contact Center. In April 2013, I joined the Virtual
11 Contact Center’s Customer Value Initiative Team researching industry best practices. In
12 February 2014, I joined the Business Center within the Business Customer Care
13 Department and became a subject matter expert in Complex Billing and Commercial &
14 Industrial rates. In April 2019, I was promoted as a Business Customer Solutions Account
15 Manager where I worked directly with customers on a variety of reactive requests related
16 to Complex Billing, Rates and Tariffs, Field Operations, Outage and Reliability, and
17 Project Support. I ensured any questions, concerns, or requests were addressed and
18 resolved to provide the best possible customer experience. In May 2023, I joined the Rates
19 and Regulations Department as a Tariff Analyst and in May 2024, I was promoted to Senior
20 Tariff Analyst. My primary responsibilities include tariff filings, developing tariff exhibits
21 for rate cases, rate implementation, complex billing, and preparing rate and monthly bill
22 comparisons. In addition, I have attended Michigan State University’s Institute of Public
23 Utilities (IPU) Accounting and Rate Making Course.

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1 **Q. Have you previously testified before the Michigan Public Service Commission**
2 **(“MPSC” or the “Commission”)?**

3 Yes. I have filed direct testimony in the following cases:

4 Case No. U-21374 Voluntary Green Pricing programs; and

5 Case No. U-21585 Electric General Rate Case.

6 **PURPOSE OF TESTIMONY**

7 **Q. What is the purpose of your direct testimony in this proceeding?**

8 A. The purpose of my direct testimony is to present the Company’s proposed tariff language
9 changes to its electric rate schedules.

10 **EXHIBITS**

11 **Q. Are you sponsoring any exhibits in this case?**

12 A. Yes, I am sponsoring the following exhibits:

13 Exhibit A-96 (BAG-1) Summary of Tariff Changes; and

14 Exhibit A-16 (BAG-2) Schedule F-5 Proposed Electric Tariff Sheets
15 (M.P.S.C. No. 14 Redlined Version).

16 **Q. Were these exhibits prepared by you or under your direction and supervision?**

17 A. Yes.

18 **Q. Please explain Exhibit A-96 (BAG-1) – Summary of Tariff Changes.**

19 A. Exhibit A-96 (BAG-1) provides a summary and explanation of the changes proposed in
20 this filing to the tariffs in the Company’s Electric Rate Book.

21 **Q. Please describe Exhibit A-16 (BAG-2), Schedule F-5, Proposed Electric Tariff Sheets**
22 **(MPSC No. 14 Redlined Version).**

23 A. Exhibit A-16 (BAG-2), Schedule F-5 contains all proposed changes to the Company’s
24 current electric tariffs in the Rate Book for Electric Service (M.P.S.C. No. 14 – Electric),

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presented in redlined format. Existing tariff language proposed for deletion is shown with red strikethrough formatting, while new proposed language is indicated by blue underlined and italicized formatting. Some changes are discussed in the testimony of other Company witnesses, such as the rationale for price changes to the Company's electric rate schedules, which are supported by the Company's rate design witness, Laura M. Connolly.

Q. Please explain the proposed changes to New Service Connection fees.

A. Supported by Company witness Jennifer M. Partlan, the Company proposes to introduce an overhead service connection fee and update the existing underground service connection fee for Residential and General Service Customers. The changes are based on inflation rates and a three-year average length of service.

Q. Why is the Company proposing to introduce an overhead service connection fee?

A. The Company proposes to introduce a service fee for overhead connections that mirrors the proposed fee for underground connections. This change is intended to promote fairness by applying a uniform fee structure for new service installations, regardless of the connection type. Additionally, the proposal supports customer adoption of the more reliable underground option and aligns with the Company's Reliability Roadmap.

Q. Why is the Company proposing to adjust the underground service connection fees?

A. The Company is proposing to revise the current underground service connection fee to reflect inflationary cost increases that have occurred since the fees were last updated in Case No. U-9346 approved for service rendered on and after August 6, 1993.

Q. What calculations were used to determine the proposed service connection fees?

A. The proposed fees are based on a three-year average service connection length of 132 feet. To simplify the structure and better reflect current economic conditions, the Company

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proposes replacing the existing per-foot charge with a flat fee of \$1,300 for Residential Customers and \$2,200 for General Service Customers. These proposed amounts were derived by applying the cumulative inflation rate over the past 31 years to the current per-foot charges and multiplying by the average service length. The calculation is provided below, supported by Company witness Partlan, whose testimony addresses the associated Low Voltage Distribution (“LVD”) work and cost considerations for New Business.

o Residential:

- Current Fees: \$4.50/ft (\$9.93/ft cost of inflation)
- Proposed Fees: $(\$9.93 \times 132) = \$1,310.76$

o General Service:

- Current Fees: \$6.50/ft (\$16.88/ft cost of inflation)
- Proposed Fees: $(\$16.88 \times 132) = \$2,228.16$

Q. Please explain the proposed changes to Rule C5.4 Shut Off Protection Plan.

A. The Company proposes to increase the eligibility for the Shut Off Protection Plan (“SPP”) from 200% to 400% of the federal poverty level. This change aims to provide support for a larger segment of moderate-income customers as outlined by Company witness Jessica R. Byrom.

Q. Please explain the changes to Rule C5.5 Non-Transmitting Meter Provision.

A. Eligible customers who elect a non-transmitting meter are served under the applicable rates in accordance with Rule C5.5, Non-Transmitting Meter Provision. Currently, two potential upfront charges apply, depending on when the customer provides notice to opt out. However, because the Company has completed the initial deployment of Advanced Metering Infrastructure (“AMI”) meters for all customers who have not opted out, the distinction between early and late opt-outs is no longer necessary. Accordingly, the Company proposes to simplify the fee structure by implementing a single upfront charge for all customers who elect to opt out, regardless of timing. This change is intended to

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1 promote consistency and fairness in the administration of the provision, while maintaining
2 the existing eligibility criteria as defined in the tariff.

3 **Q. Is the Company proposing any other changes to its AMI Opt-Out Charges?**

4 A. Yes. Supported by Company witness Michael P. Kelly, the Company is proposing updated
5 AMI opt-out charges based on a re-evaluation conducted in compliance with the
6 Commission's directive in the Final Order in Case No. U-21585. The proposed charges,
7 as calculated by Company witness Kelly, are as follows:

- 8 • Up Front Charge: \$216.22
- 9 • Monthly Charge: \$3.09

10 **Q. Please explain the removal of Sheet Nos. C-50.00 – C-51.00 and D-80.00.**

11 A. The Company proposes to remove the tariff sheets associated with the Experimental
12 Advanced Renewable Program ("EARP")—Anaerobic Digestion Program ("AD Program")
13 because the program is closed to new participants and has had no active customers since
14 May 2023. The removal reflects the current status of the program and ensures the tariff
15 remains accurate and up to date.

16 **Q. Please explain the changes to General Service Secondary Time of Use Rate GSTU.**

17 A. The Company is proposing to revise the availability of Rate GSTU to clarify that customers
18 may participate in Demand Response ("DR") programs while taking service under this rate.

19 **Q. Why is the Company proposing to modify the availability of Rate GSTU?**

20 A. Full Service customers taking service under Rate GSTU are currently eligible to participate
21 in DR programs, as outlined on Sheet No. D-10.00, Rate Categories and Provisions. The
22 proposed revision is intended to clarify the eligibility within the GSTU tariff itself,
23 ensuring consistency and transparency in how the rate is administered.

1 **Q. Please explain the Company's proposed modification to the Aggregate Peak Demand**
2 **Service ("GAP") provision.**

3 A. The Company is proposing to revise the GAP provision that allows for discretionary
4 enrollment of customers who may not meet all of the stated eligibility criteria. Specifically,
5 the Company seeks the ability to consider participation by customers with fewer than seven
6 accounts and/or accounts with a lower average On-Peak Billing Demand than the current
7 250 kW demand threshold. This flexibility would be exercised solely at the Company's
8 discretion and would not alter the fundamental structure or intent of the provision.

9 **Q. What is the purpose of this proposed change?**

10 A. The purpose of this change is to provide the Company with administrative flexibility to
11 accommodate unique customer circumstances that may not fit neatly within the existing
12 eligibility framework. In some cases, customers may narrowly miss one of the criteria but
13 still be appropriate candidates for participation. This change allows the Company to
14 evaluate such situations and make reasonable determinations without requiring a formal
15 tariff revision each time.

16 **Q. Will this change affect other customers or the overall administration of the tariff?**

17 A. No. This change does not alter the structure or pricing of the GAP provision and is not
18 expected to impact other customers. It simply provides the Company with the ability to
19 consider exceptions in limited circumstances, which can improve customer service and
20 responsiveness without compromising the integrity of the tariff.

21 **Q. Please explain the changes to the Large Economic Development Rate LED.**

22 A. The Company proposes adding a Power Factor adjustment to Rate LED. This adjustment
23 is similar to the recently approved Power Factor adjustment for Rates GP, GPD, GPTU,

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1 and EIP in Case No. U-21585, but with an increased penalty band – up to an average Power
2 Factor of 0.909 – compared to the penalty bands for these other rates. Additionally, the
3 Company proposes including a facilities allowance. Further details are provided by
4 Company witness Connolly.

5 **Q. Are there any other tariff changes being proposed by the Company?**

6 A. Yes. The remainder of the Company's proposed tariff changes are described in Exhibit
7 A-96 (BAG-1), Summary of Tariff Changes. This exhibit provides a summary and
8 explanation of all the tariff changes being proposed by the Company in this case.

9 **Q. Does this conclude your direct testimony?**

10 A. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

KENDRA K. GROB

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

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1 **Q. Please state your name and business address.**

2 A. My name is Kendra K. Grob, and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

4 **Q. By whom are you employed?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

6 **Q. What is your current position with Consumers Energy?**

7 A. I am currently the Senior Manager, Benefits.

8 **Q. What are your responsibilities as Senior Manager, Benefits?**

9 A. I am responsible for the design, implementation, and administration of the Company’s
10 retirement and health care plans, and our department oversees the benefit plans for
11 employees and retirees. In the retirement benefits area, the Company contributes to the
12 cost of the Pension Plans, the Defined Company Contribution Plan (“DCCP”), and the
13 401(k) Employees’ Savings Plan (“ESP”). My responsibilities include designing,
14 reviewing, and administering competitive, cost-effective, quality plans that attract and
15 retain qualified employees to serve customers. These plans aim to provide a portion of an
16 employee’s retirement income, along with social security benefits and personal savings.

17 In the benefits area, the Company contributes to the cost of health care plans
18 (medical, prescription drug, dental, including Health Savings Accounts (“HSAs”) and
19 Health Care Flexible Spending Accounts (“HCFsAs”)), life insurance, and Long-Term
20 Disability (“LTD”) insurance. Our department also designs, reviews, and administers these
21 health care and other benefit plans to ensure they are competitive, cost-effective, and of
22 high quality for employees and retirees, helping to attract and retain qualified employees
23 to serve customers. Additionally, the Company offers several benefit plans at group

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discounted rates, requiring employees to pay the full cost of the coverage elected. These voluntary plans include accidental death and dismemberment insurance, health care and dependent care flexible spending accounts, vision insurance, and dependent term life insurance. In 2024, the Company added hospital indemnity, critical illness, and accident benefits. These insurance plans help attract and retain qualified employees by protecting them and their families from significant financial loss in various 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 overall well-being.

Q. What is your formal educational experience?

A. In 1998, I graduated from Siena Heights University in Adrian, Michigan 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.

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1 In 2007, I began working for Amcor Rigid Packaging as a Senior Benefits
2 Specialist. My area of responsibility was retirement plans, disability, and life insurance
3 plans. In this role, I was responsible for the relationship with vendors and the
4 administration of plans for our employees. I was the primary vendor contact for these areas
5 and was heavily involved in all Request for Proposal processes in choosing vendors. While
6 in this position, I sat on the Retirement Committee as the Secretary and took part in plan
7 design and fund selections for both the pension and the savings plan.

8 In 2020, I joined Consumers Energy as Manager, Retirement Plans. My
9 responsibilities included complete oversight for the Company pension and savings plans
10 (401k). In this role, I ensured the Company provides retirement benefits to active and
11 retired employees while maintaining accurate legal compliance with the Internal Revenue
12 Service.

13 In March 2024, I was promoted to Senior Manager, Benefits. In this role I
14 continued complete oversight for the Company pension and savings plans (401k) with the
15 addition of assuming responsibility for health and welfare benefits.

16 **Q. Are you a member of any professional societies or trade associations?**

17 A. I am professionally certified as a Human Resources Professional through both SHRM and
18 HRCI.

19 **Q. What is the purpose of your direct testimony?**

20 A. The purpose of my direct testimony is to provide support for the Company's costs related
21 to the electric business portion of retirement, health care, life insurance, LTD plans, and
22 other benefits provided to its employees and retirees. In Part I of my direct testimony,
23 I will address the retirement benefits plans. In Part II of my direct testimony, I will address

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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-97 (KKG-1)	Summary of Actual and Projected Benefits O&M Expenses for the Year 2024 and Test Year Twelve Months Ending April 30, 2027;
Exhibit A-98 (KKG-2)	CMS Energy – Pension Plans A and B - ASC 715 Pension Expense Estimates (\$ millions);
Exhibit A-99 (KKG-3)	CMS Energy - ASC 715 OPEB Expense Estimates (\$ millions); and
Confidential Exhibit A-100 (KKG-4)	CMS Energy – Actuarial Letter of Support for 2025 Year Projections.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please describe Exhibit A-97 (KKG-1).

A. Exhibit A-97 (KKG-1), page 1, summarizes 2024 actual expenses through the 12 months ending April 30, 2027, projected electric 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 2024 for each plan. Column (c) provides the projected expense for the 12 months ending April 30, 2027. Page 2 provides information on inflation factor projections and adjustments using the methods discussed in this testimony and included in column (i). Column (j) is the projected test year O&M expense and is the sum of columns (b) + (d) + (f) + (h) + (i).

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1 **Q. Please describe Exhibits A-98 (KKG-2), A-99 (KKG-3), and Confidential Exhibit**
2 **A-100 (KKG-4).**

3 A. Exhibits A-98 (KKG-2) and A-99 (KKG-3) provide the Aon actuarial projections for
4 Pension and Other Post Employment Benefit (“OPEB”) expenses for the years identified.
5 Both the Pension and OPEB projections in these exhibits provided by the Aon actuaries are
6 from the year-end 2024 measurement of the Pension and OPEB plans and with current
7 market conditions as of December 31, 2024. A letter from the actuary regarding the
8 accuracy and completeness of the projections is included in Confidential Exhibit A-100
9 (KKG-4).

10 **I. RETIREMENT BENEFITS PLANS**

11 **Q. Which retirement benefits are you addressing in this section of your direct testimony?**

12 A. I am addressing the Pension Plans, DCCP, and ESP. These expenses are shown on Exhibit
13 A-97 (KKG-1), page 1, lines 1 through 3.

14 **Q. How are the Pension Plans, DCCP, and ESP expenses that are common to electric**
15 **and gas operations allocated to the electric portion of the business?**

16 A. Expenses common to both the electric and gas operations associated with the Pension
17 Plans, DCCP, and ESP are allocated based on the relationship of employee labor dollars
18 charged to electric operations compared to the labor dollars charged to both electric and
19 gas operations. These allocations studies are performed by the Accounting Department.
20 The electric portion of the O&M expense for these plans is shown on Exhibit A-97
21 (KKG-1), page 1.

Pension Plans

Q. Would you please explain your Exhibit A-97 (KKG-1), line 1, which begins with (\$51,785,000) in 2024?

A. Exhibit A-97 (KKG-1), page 1, line 1, shows the actual 2024 pension expense and the projected expense for 12 months ending April 30, 2027, attributable to the electric portion of the utility operations.

Q. How does the Company determine its expense for the Pension Plans?

A. The pension expense is determined using actuarial analysis that is performed in accordance with Accounting Standards Codification ("ASC") 715. Consumers Energy follows Generally Accepted Accounting Principles ("GAAP") for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodology and assumptions required to properly calculate and account for pension expense which includes evaluation of market conditions at each of the Pension Plan's measurement dates. In addition, the Company's auditor rigorously reviews the process to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of pension expense. Pension expense is determined based on actuarially reviewed employee census data, plan provisions, plan assets, and certain other assumptions. Year-end disclosure information is also produced, based on these accounting standards, to show a reconciliation of plan assets and liabilities at the end of the Company's fiscal year. For this electric rate case, the Pension Plans were measured in January for year-end December 31, 2024.

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

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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 several 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

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1 create a yield curve that determines the effective discount rate for all maturities of pension
2 payments. The model itself does not change annually, but the discount rate typically will
3 be updated based on the most current market conditions.

4 **Q. Please describe how the expected return on plan assets is set each year.**

5 A. The Company uses future expected capital market assumptions, asset allocation
6 information, and other resources provided by its consultants, which may include survey
7 data and analysis of the Pension Plan's asset allocation. The expected return assumption
8 is based on long-term expectations and not short-term returns. The Company uses all this
9 information to establish an expected return on plan assets assumption that best estimates
10 its expectation. While this assumption is reviewed for each plan measurement, it may or
11 may not be updated annually depending on the information that is presented.

12 **Q. Does the Company apply Accounting Standard Update ("ASU") No. 2017-07**
13 **Improving the Presentation of Net Periodic Pension/OPEB Costs Standard in this**
14 **case?**

15 A. Yes, the Company adopted the ASU No. 2017-07 standard as of January 1, 2017, and has
16 applied the Standard in this case for both Pension and OPEB. This ASU No. 2017-07
17 standard allows only the service cost component of expense to be recorded as an operating
18 expense and all other benefit-cost components are to be recorded outside operating income.
19 The Standard also allows only service costs to be capitalized, while all other cost
20 components are recorded to net income immediately.

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1 **Q. Please describe the development of the Pension Plans' expense shown on Exhibit A-97**
2 **(KKG-1), page 1, line 1, which begins with (\$51,785,000) for 2024.**

3 A. The annual pension expense shown on Exhibit A-97 (KKG-1), page 1, line 1, for the
4 electric utility is based upon Aon's actuarial determination of each plan's total expense for
5 that year in accordance with ASC 715 and includes plan administration fees, aggregated
6 for total pension expense. The Consumers Energy pension expense determined by Aon
7 plus administration fees are allocated to the electric and gas portions of the utility using the
8 Accounting Department methodology described earlier. This allocation resulted in the
9 actual electric utility O&M expense for Pension of (\$51,785,000) in 2024, and projected
10 expense of (\$45,156,000) for the 12 months ending April 30, 2027. Exhibit A-97 (KKG-1),
11 page 2, line 1, column (i), compares the Aon actual calculation of expense with the 2024
12 actual expense, as adjusted for 2025, 2026, and 2027 inflation, to calculate other
13 adjustments.

14 **Q. Have there been any significant plan design changes to the Pension Plan in recent**
15 **years?**

16 A. Yes. The Company split its Pension Plan into two plans as of January 1, 2018. Generally,
17 all participants who were employees of the Company on August 1, 2017, were included in
18 Pension Plan A. All other participants, including any Cash Balance participants, were
19 assigned to Pension Plan B. No changes to participant benefits occurred because of this
20 change. The Company decided to make this change to help manage expenses of the
21 Pension Plans by extending the amortization period for the inactive group and enabling the
22 mitigation of Pension Benefit Guarantee Corporation premium variability.

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1 **Q. Did the Company make any cash contributions to the Pension Plans in 2024?**

2 A. No, the Company did not contribute to either plan in 2024.

3 **Q. Will the Company make any cash contributions to the Pension Plans in 2025?**

4 A. No cash Pension Plan contributions are required in 2025 to avoid benefit restrictions. Any
5 contributions the Company elects to make during these periods of time will depend upon
6 future decisions of the Company regarding funding policy, the future value of plan assets
7 and liabilities, and any potential legislative guidance or changes.

8 **Q. Why did the pension expense increase for the projected test year from 2024?**

9 A. The Pension expense increased due to lower-than-expected asset returns in 2024.

10 **Q. Have any changes recently been made to the Pension Plans' benefits?**

11 A. Effective November 1, 2020, the Company changed the unreduced early retirement age
12 from 62 to 61 for the Company's pension union eligible employees. This benefit
13 enhancement allows for the Company to continue to retain current union pension eligible
14 employees since they can now retire one year earlier but not lose any percentage of their
15 pension benefit and was very well received. The additional changes in the projected
16 pension expense estimates from 2024 to the 12 months ending April 30, 2027, are primarily
17 the result of economic conditions external to the Pension Plans over which the Company
18 has no control.

19 **DB Pension/OPEB Volatility Mechanism ("VM")**

20 **Q. Please describe the DB Pension/OPEB VM that the Company is proposing.**

21 A. The Company requests the ability to continue its implementation of a DB Pension/OPEB
22 VM, previously authorized by the MPSC in Case Nos. U-21585 and U-21389. The
23 sensitivity of DB Pension/OPEB expenses to changes in asset returns or other assumptions

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creates a significant potential for large variability in future expenses. Customers benefit from a mechanism that eliminates the risk of future volatility in expense. Without a mechanism, there could be substantial, unanticipated swings in the DB Pension/OPEB expense. The proposed mechanism, which mirrors the mechanism that has existed since 2023, would protect customers from this volatility by allowing the Company to defer annually the difference between the DB Pension/OPEB expense included in rates versus the actual annual DB Pension/OPEB expense recorded by the Company pursuant to ASC 715.

Q. Is the mechanism symmetrical?

A. Yes. Under the mechanism, if the actual annual DB Pension/OPEB expense is less than the expense approved in rates, the difference would be recognized as a regulatory liability and amortized over 10 years starting the following January. Similarly, if actual annual DB Pension/OPEB expense is greater than the expense approved in rates, the difference would be recognized as a regulatory asset and amortized in the same manner. Any amortization of these regulatory assets or liabilities would be included in future general rate cases. The mechanism is not only fair but similar mechanisms have been approved by the Commission for other utilities in contested cases. See, e.g., MPSC Case No. U-21297, December 1, 2023 Order, pages 222-224; MPSC Case No. U-21291, November 7, 2024 Order, page 160.

Q. Please describe the Pension VM Deferral on Exhibit A-97 (KKG-1), page 1, line 7, column (b), which begins with \$10,729,000 for 2024.

A. Per the Settlement Agreement in Case No. U-21224, the Company was authorized to defer actual DB Pension expense different than the approved annual amount of (\$29,700,000) starting in 2023. In the Case No. U-21389 Order, the Company was authorized to defer the

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1 actual DB Pension expense, which different than the approved annual amount of
2 (\$43,327,000) starting in March 2024. In 2024, the DB Pension expense was lower than
3 the approved amounts as shown on Exhibit A-97 (KKG-1), page 1, line 1, column (b), of
4 (\$51,785,000) for 2024. The Company compared the authorized amount for two months,
5 totaling \$4,950,000, by taking the annual authorized amount in Case No. U-21224
6 (\$29,700,000), dividing it by 12, and multiplying by two months for January and February
7 2024. For the months of March to December 2024, the Company compared ten months of
8 authorized expenses totaling (\$36,106,000). This was calculated by taking the 12 months
9 authorized amount in Case No. U-21389 (\$43,327,000), dividing it by 12, and multiplying
10 by ten months. Adding the two-month authorized amount of (\$4,950,000) to the ten-month
11 amount of (\$36,106,000) results in a total authorized amount for 2024 of (\$41,056,000).
12 The Company recorded the difference between the actual DB Pension expense and the
13 approved rate expense for the Pension VM for the year 2024. The Pension VM deferral of
14 \$10,729,000 resulted in an increased expense for 2024, and the Company consequently
15 recorded a Pension VM regulatory liability of \$10,729,000.

16 **Q. Please describe the Pension VM Amortization on Exhibit A-97 (KKG-1), page 1,**
17 **line 9, column (c), which begins with (\$1,912,000) for 12 months ending April 30, 2027.**

18 A. The Pension VM amortization includes deferred amounts being amortized from 2023 to
19 2025. These deferred Pension VM amounts are being amortized over a 10-year period,
20 consistent with the approach used in Case Nos. U-21585, U-21389, and U-21224.

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1 **Q. Please describe the OPEB VM Deferral on Exhibit A-97 (KKG-1), page 1, line 8,**
2 **column (b), which begins with \$3,579,000 for 2024.**

3 A. Per the Settlement Agreement in Case No. U-21224 the Company was authorized to defer
4 actual OPEB expense different than the approved annual amount of (\$65,700,000) starting
5 in 2023. In the Case No. U-21389 Order, the Company was authorized to defer actual DB
6 Pension expense different than the approved annual amount of (\$39,608,000) starting in
7 March 2024. In 2024, the OPEB expense was lower than the approved amounts as shown
8 on Exhibit A-97 (KKG-1), page 1, line 5, column (b), of (\$47,536,000) for 2024. The
9 Company compared two months authorized of (\$10,950,000), taking the authorized amount
10 in Case No. U-21224 (\$65,700,000) dividing by 12 and times by two months for January
11 and February 2024 and for months March to December 2024, the Company compared ten
12 months of authorized (\$33,007,000), taking the 12-month authorized amount in Case No.
13 U-21389 (\$39,608,000) dividing by 12 and times by ten months. Taking the (\$10,950,000)
14 plus (\$33,007,000) gives the total authorized amount for 2024 of (\$43,957,000). The
15 Company recorded the difference between the actual OPEB expense and the approved rate
16 expense for the OPEB VM for the year 2024. The OPEB VM deferral of 3,579,000 resulted
17 in an increase expense for 2024, and the Company consequently recorded a Pension VM
18 regulatory liability for \$3,579,000.

19 **Q. Please describe the OPEB VM Amortization on Exhibit A-97 (KKG-1), page 1,**
20 **line 10, column (c), which begins with \$1,813,000 for 12 months ending April 30, 2027?**

21 A. The OPEB VM amortization includes the deferred amounts being amortized for the years
22 2023 to 2025. The deferred OPEB VM is being amortized over 10 years which is consistent
23 with how the VM in Case Nos. U-21585, U-21389, and U-21224 operated.

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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. To stay competitive by offering a benefits package that attracts and retains qualified and talented employees for the benefit of the customer, the Company replaced the Final Average Pay and Cash Balance versions of the qualified DB Pension Plan with the qualified DCCP. This change applied to all existing Cash Balance participants and newly hired employees starting from September 1, 2005.

Q. Are there any employees included in the DCCP that were hired before September 1, 2005?

A. Employees hired between July 1, 2003, and August 31, 2005, who were covered under the Cash Balance version of the defined benefit DB Pension Plan, became participants in the DCCP as of September 1, 2005. Concurrently, additional pay credits under the Cash Balance version of the defined benefit DB Pension Plan were discontinued for this specific group of employees.

Q. Will the Cash Balance version of the DB Pension Plan accept any new employees as participants?

A. Similar to the Final Average Pay DB Pension Plan, the Cash Balance version of the DB Pension Plan now has a limited group of participants. Over time, this group will gradually decrease until there are no longer any employees or retirees covered under this plan.

Q. Please provide a general description of the DCCP.

A. The DCCP currently provides an employer funded cash contribution as a percentage of an employee's base pay to the ESP—the percentages vary with years of service as described

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1 below. No employee contribution is required to receive the employer contribution. All
2 existing Cash Balance Plan employee participants and employees hired on and after
3 September 1, 2005, participate in the DCCP as part of their retirement benefit package.

4 **Q. Have any recent changes been made to the DCCP?**

5 A. No changes have been made to the DCCP since 2021. Effective January 2021, for the
6 Company's union employees, the DCCP provides an 8% to 10% (previously 5% to 7%)
7 employer funded cash contribution based upon the union employee's service time with the
8 Company. New union hires receive an 8% contribution, which increases to 9% when they
9 have six years of service with the Company. When union employees reach 12 years of
10 service, they receive a 10% employer contribution. This service-based contribution
11 approach for the DCCP serves as a talent retention mechanism. The increase in the union
12 DCCP contributions was needed for the Company to remain competitive to attract qualified
13 employees and retain talent that maximizes the efficiency of the Company's labor force
14 and reduces costly turnover. Retaining trained, experienced, and motivated employees
15 provides better service for customers.

16 The Company's exempt and non-exempt employees will continue to receive the
17 DCCP which was effective in January 2016. The DCCP provides a 5% to 7% (previously
18 6%) employer funded cash contribution based upon the employee's service time with the
19 Company. New hires receive a 5% contribution, which increases to 6% when they have
20 six years of service with the Company. Employees receiving a 6% contribution before
21 January 1, 2016, continue to receive their 6% employer contribution. When employees
22 reach 12 years of service, they receive a 7% employer contribution. This service-based
23 contribution approach for the DCCP serves as a talent retention mechanism and helps

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1 contain the cost of the DCCP for the benefit of the customer as all new hires starting in
2 2016 began receiving a 5% (previously 6% for new hires) employer contribution.

3 **Q. Would you please explain your Exhibit A-97 (KKG-1), page 1, line 2, which begins**
4 **with \$14,774,000 in 2024?**

5 A. Exhibit A-97 (KKG-1), page 1, line 2, represents the electric operations O&M expense
6 related to the DCCP. The actual electric operations expense for this plan in 2024 was
7 \$14,774,000 as shown in column (b). Column (c) shows the projected electric DCCP
8 expense of \$16,507,000 for the 12 months ending April 30, 2027. DCCP costs are
9 projected to increase using merit salary rate factors of 3.2% for 2024 through the 12 months
10 ending April 30, 2027. If a DB Pension individual retires, the new person hired to replace
11 their role is entered into the DCCP plan. For the projected years 2024 through the
12 12 months ending April 30, 2027, costs were split using 62% electric and 38% gas, with
13 52% capital on electric expenses.

14 **Q. As a result of the revised eligibility requirements for participation in the Final**
15 **Average Pay DB Pension Plan or the Cash Balance version of the DB Pension Plan, is**
16 **it correct to say that all new hire employees who started on September 1, 2005, and**
17 **after will receive their retirement benefits through plans that are referred to as**
18 **defined contribution type plans?**

19 A. Yes. The primary plans that will provide monetary benefits to this group of employees
20 upon retirement are the DCCP and the ESP.

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ESP

Q. Please explain briefly the ESP.

A. The ESP is a defined contribution retirement savings program funded by employee and employer contributions. A portion of employee contributions is matched by Consumers Energy. Prior to January 2022, the Company matched 100% of the employees' first 3% in contributions and 50% of the employees' next 2% in contributions to the ESP. Employee contributions beyond 5% were not matched by the Company. Consumers Energy's expense includes the Company's matching contributions, and the payments made to Fidelity Investments for administration of the program.

Q. Have any recent changes been made to the ESP?

A. Effective in January 2022, the Company match design has changed only for Salaried (exempt and non-exempt) employees to 100% of employee contributions up to 6% of the employee's salary. Employee contributions beyond 6% will not be matched by the Company. This change will help to keep the ESP cost and talent retention competitive in the market for the benefit of customers. The Union employees will continue receiving matching contributions of 100% for employee contributions of up to 3% of the employees' salary, and then 50% of employee contributions up to the next 2% of the employees' salary.

Q. Would you please explain your Exhibit A-97 (KKG-1), page 1, line 3, which begins with \$11,396,000 in 2024?

A. Exhibit A-97 (KKG-1), page 1, line 3, represents the Company's electric operations expense related to the ESP. In 2024, the actual electric utility O&M expense for the ESP was \$11,396,000. The electric utility's ESP O&M expense projected for the test year is \$12,731,000. Savings Plan costs are projected to increase using merit salary rate type

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1 increase of 3.2% for 2024 through the 12 months ending April 30, 2027. For the projected
2 years 2024 through the 12 months ending April 30, 2027, costs were split using 62%
3 electric and 38% gas, with 52% capital on electric expenses.

4 **Q. Is the ESP employer matching program important to attracting and retaining**
5 **employees?**

6 A. Yes.

7 **Q. Please explain why the ESP employer matching program is important to attract and**
8 **retain employees.**

9 A. The ESP with a match is commonly available from Michigan employers as well as from
10 other utility company employers that Consumers Energy competes with for employee
11 talent. It is necessary to continue providing this highly visible, competitive benefit to
12 employees of Consumers Energy to continue attracting and retaining competent employees
13 needed by the Company, particularly considering the large number of retirement-eligible
14 employees at the Company. Attracting qualified employees and retaining this talent
15 maximizes the efficiency of the Company's labor force and reduces costly turnover. Safe,
16 reliable, and affordable electric service begins and ends with the Company's people.
17 Investing in and retaining trained, experienced, and motivated employees' benefits
18 customers as much as, or more than, any investment in infrastructure.

19 **Q. Is the ESP employer match discretionary?**

20 A. It is not discretionary for union employees. A provision in the Working Agreement ratified
21 in 2005 with Operating Maintenance & Construction ("OM&C") and Virtual Call Center
22 ("VCC") union employees assured these employees that the match would not be suspended

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1 during their five-year contract. This provision has remained in effect for all following
2 contracts up to and including the most recent five-year contract negotiated in 2020.

3 With respect to non-union employees, there is not a similar contractual prohibition
4 against suspension. However, the ESP employer match is part of an overall competitive
5 benefits package and employees depend upon its continuation so they can accumulate
6 savings for retirement. This is a benefit that helps the Company attract and retain qualified
7 and talented employees. From a practical standpoint, the Company views the employer
8 match as non-discretionary.

9 **II. HEALTH CARE, LIFE INSURANCE, LTD PLANS, AND**
10 **OTHER BENEFITS**

11 **Q. Which health care and insurance benefits are you addressing?**

12 A. I am addressing active employee health care (including HSAs and HCFsAs), life insurance,
13 LTD plans, and other benefits of absence management and educational assistance, as well
14 as retiree health care and life insurance plans. These expenses are shown on Exhibit A-97
15 (KKG-1), page 1, lines 4 through 6.

16 **Q. Are the expenses for active employee health care (including HSAs and HCFsAs), life**
17 **insurance, and LTD benefits determined in the same way as expenses for retiree**
18 **health care and life insurance benefits?**

19 A. No. The expenses for active employees are based upon the actual costs for these benefits
20 that are expected to be incurred. The expenses for retirees are determined using actuarial
21 analysis, which is performed by the Company's actuary, in accordance with ASC 715,
22 formerly known as Financial Accounting Standards ("FAS") 106.

1 **Q. How were the portions of active employee and retiree health care (including HSAs**
2 **and HCFSAs), life insurance, LTD, and other benefits costs allocated to electric O&M**
3 **expense determined?**

4 A. The portion of the Company's total program expenses attributable to the electric utility was
5 allocated based upon an annual study by the Accounting Department of the relationship of
6 the number of employees in the electric utility to the total number of employees in both the
7 electric and gas utility. The amount allocated to the electric utility is allocated between
8 O&M expense and capital expense based upon the Accounting Department's formula. For
9 the projected years 2024 through the 12 months ending April 30, 2027, costs were split
10 using 56% electric and 44% gas, with 64% capital on electric expenses.

11 **Active Health Care (Including HSAs and HCFSAs), Life Insurance,**
12 **LTD, and Other Benefits**

13 **Q. Please describe the development of the active health care (including HSAs and**
14 **HCFSAs), life insurance, and LTD expense levels that are shown on Exhibit A-97**
15 **(KKG-1), page 1, line 4, which begins with \$29,089,000.**

16 A. Exhibit A-97 (KKG-1), page 1, line 4, contains electric operations O&M expenses for the
17 Company-funded benefit plans for active employees' health care (including HSAs and
18 HCFSAs), life insurance, and LTD. The primary component of this expense is health care.
19 Life insurance and LTD make up a much smaller portion of the expense. In 2024, the
20 Company incurred an actual combined expense of \$29,089,000 for health care, life
21 insurance, and LTD for electric operations. The projected electric operation expense for
22 these benefits for the projected test year is \$33,385,000.

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1 **Q. What factors did you consider when projecting the test year's expenses for health**
2 **care, life insurance, and LTD?**

3 A. In projecting the test year's health care expenses, a number of factors were considered. The
4 primary factors included current and projected inflation factors and a review of 2023 and
5 2024 national health trends/costs survey information provided by Willis Towers Watson
6 ("WTW") actuarial consulting. Additional factors considered were the Company's medical
7 and prescription drug carrier's health cost and claims experience expectations, the
8 continuing rapid rise in availability and price of specialty prescription drugs, the current
9 employee headcount, and the continuing cost increase impacts of national health care
10 reform.

11 **Q. Please explain how these factors were used to determine the Company's expected**
12 **health care costs.**

13 A. The Company has determined that using the inflation factors in this case will keep cost
14 increases in line with inflation amounts. Exhibit A-97 (KKG-1), page 2, line 4, column (i),
15 compares the projected test-year expense with the 2024 actual expense, adjusted for 2025,
16 2026, and 2027 inflation, to calculate other adjustments.

17 To further understand projected health care trends and costs, the Company and
18 WTW reviewed expected health care trends and costs survey information from several
19 large consulting firms. The Company and WTW also reviewed the Company's actual
20 health care claims experience for employees and retirees in its health plans - Blue
21 Cross/Blue Shield of Michigan ("BC/BS") and Express Scripts. This analysis of the
22 Company's health plans revealed that the Company's workforce is older than the average
23 age of the population insured by the BC/BS and Express Scripts plans, and as a result, the

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1 Company's health plans have a higher expected utilization rate that is associated with an
2 older covered population. Of the Company's current workforce, as of December 31, 2024,
3 47% of employees are over age 45; 32% are over age 50; and 18% are over age 55. The
4 Company understands the older age of its workforce is expected to lead to a higher health
5 care expense (primarily due to utilization of services).

6 To project future health care expenses, the Company and WTW also considered all
7 the plan changes and programs that the Company has already implemented. These changes
8 include sharing expected health care expense increases with employees through plan design
9 changes like increased deductibles, copayments, and out-of-pocket maximums; increasing
10 employee premium contributions for coverage; adding telehealth benefits to medical plans
11 to lower expense; educating employees regarding the prudent and informed use of health
12 care benefits; promoting use of preventive benefit services; promoting well-being through
13 Live Well 365, which is integrated into all medical plan designs, that encourages and
14 rewards plan participants for taking steps toward healthier lifestyles; securing favorable
15 pricing on prescription drugs obtained through a large employer prescription drug
16 collaborative; negotiating lower administrative fees with health plans and promoting
17 enrollment into the Consumer Directed Health Plan ("CDHP"), a high deductible health
18 plan which currently provides a Company contribution to the participant's HSA.

19 The Company and WTW also considered the specific changes to the union
20 employees' health care plan benefits as negotiated in its 2020 through 2025 contracts, as
21 well as changes made to the employees' health care benefit plans in 2021 described in
22 detail later in this direct testimony. While there are very tangible savings in future health
23 expenses to the Company and its customers as a result of these changes to employee health

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1 care benefit plans, the Company believes a portion of these savings will be offset by
2 increased health expenses incurred under national health care reform requirements (like
3 Patient Centered Outcomes Research Institute fees, employer mandate shared
4 responsibility administrative/reporting requirements, and potential penalties) as well as
5 increased prescription expenses due to the availability of new and expensive specialty
6 prescription drugs in the market. In addition, while the Company has taken numerous steps
7 to control the rising expense of health care, many of these changes are one-time events that
8 lower a plan's expense in that year to establish a new baseline moving forward, but future
9 health care expenses then continue to increase from the new baseline expense.

10 **Q. What are some of the reasons that health care costs are increasing at a level higher**
11 **than general inflation?**

12 A. There are a number of factors causing a higher rate of health care inflation than is reflected
13 in the general Consumer Price Indexes ("CPIs"). Health care costs are expected to continue
14 rising during the next several years due to an aging population living longer, additional
15 utilization of services, price increases for services, new medical technology, cost shifts
16 from government plans, mandated benefits coverage, rising provider malpractice
17 premiums, new taxes on health claims, and rapidly escalating prescription drug prices
18 including high prices for new, expensive specialty drugs. In addition, national health care
19 reform will increase Company health care costs in the near term because of eligibility
20 expansions (e.g. adult children to age 26), mandated benefits, removal of annual dollar
21 limits, additional taxes, fees, penalties, new compliance/reporting requirements, and more
22 government shifting of costs through Medicare and Medicaid expansion. These factors are
23 all outside the control of Consumers Energy. Even with all the employee and retiree health

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1 plan design and premium contribution changes made annually by the Company over a
2 number of years, including the move to Live Well 365 program incentives, health care costs
3 for the Company are still expected to continue increasing annually at a rate two to three
4 times that of general CPI inflation. The assumption that healthcare costs will only increase
5 at the general rate of inflation has not been the actual experience for many years and is not
6 expected in the foreseeable future.

7 **Q. Are increases in health care costs being experienced both locally and nationally?**

8 A. Yes. While increases in health costs have moderated, both local and national health care
9 costs continue to increase at rates greater than general CPI inflation.

10 **Q. Are the significant increases in health care costs limited to active employees?**

11 A. No. Health care costs are also increasing at a rate higher than the general CPI inflation for
12 retirees for the same reasons cited earlier. In fact, retiree expenses are generally increasing
13 at higher rates because of retirees' older ages and the resulting increases in utilization,
14 particularly in the use of prescription drugs, including higher-priced specialty prescription
15 drugs. The projected increases for active employee health care, like projected increases for
16 retiree health care, are substantial, expected to occur, and largely beyond the control of the
17 Company.

18 **Q. Please describe the development of the expense levels for active employee life**
19 **insurance and LTD costs included in Exhibit A-97 (KKG-1), page 1, line 4.**

20 A. For 2025, the Company used inflation factors of 2.1%. In 2026, the Company used 2.4%,
21 and for 2027, 2.4% was used. These expense estimates are reasonable as both life insurance
22 and LTD premium costs are based on wage and salary levels and changes to this coverage
23 throughout the year. The 2.1%, 2.4%, and 2.4% annual increases represent the normal,

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1 expected merit increases in salaries/wages, increases due to salary adjustments made for
2 job changes and promotions throughout the year, any upward movement in Company-paid
3 life insurance coverage in each annual enrollment period, and increases in premium rates
4 due to plan experience.

5 **Q. What has the Company done to control the increase in active employee and retiree**
6 **health care, life insurance, and LTD expenses?**

7 A. The Company aggressively manages these benefit costs by analyzing costs and plan
8 designs on an annual basis with our third party vendor, Willis Towers Watson. An example
9 of recent changes made to manage the cost of the Company's health care plans offered to
10 employees and retirees follows:

- 11 • Negotiated administrative fees and insured plan premium rates annually;
- 12 • Implemented health and disease management programs and added case
13 management;
- 14 • Effective January 1, 2024, the Company made a plan design change in the
15 Salaried Active Medical plans so the out-of-pocket limits for both Union and
16 Salaried employees are now the same. In addition, changes were made to
17 decrease premiums in the Salaried Active Community Blue Medical for active
18 employees;
- 19 • Eliminated eligibility for Salaried Retiree Life – Employer Paid for those who
20 retired on/after January 1, 2024. They may still participate in Retiree Life, but
21 at their own cost; and
- 22 • Effective January 1, 2025 current Salaried and Retirees (Exempt/Non-Exempt)
23 who are under age 65 as of 1/1/2025 and Spouses, and Survivors under age 65
24 were moved to the Via Benefits Health Insurance Marketplace (also known as
25 the Individual and Family Plan Marketplace) and will no longer be eligible for
26 coverage in the Blue Cross Blue Shield of Michigan/Express Scripts and Delta
27 Dental retiree group healthcare plans. Dependents under the age of 26 and
28 disabled dependents will remain on current active coverage with BCBS of
29 Michigan.

Retiree Health Care and Life Insurance

Q. Would you please explain your Exhibit A-97 (KKG-1), page 1, line 5, for retiree health care and life insurance, which begins with (\$47,536,000) in 2024?

A. Exhibit A-97 (KKG-1), page 1, line 5, reflects the actual 2024 and projected 12-month period ending April 30, 2027, electric 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 by using actuarial analysis that is performed in accordance with ASC 715. Consumers Energy follows GAAP for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodologies and assumptions required to properly calculate and account for retiree health care and life insurance expense which includes evaluation of market conditions at each of the plan's measurement dates. The calculations required by the accounting standards are performed at least annually by the plan's actuary, Aon, using information specific to the Company's OPEB plan. In addition, the Company's auditor rigorously reviews the process to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of retiree health care and life insurance expense (OPEB expense or formerly FAS 106 expense). The expense is determined based on actuarially reviewed employee census data, the plan provisions, plan assets, and certain other actuarial assumptions. Year-end disclosure information is also produced, based on these accounting standards, to provide a reconciliation of plan assets and liabilities at the

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1 end of the Company's fiscal year. For this electric rate case, OPEB was measured in
2 January for the year-end 2024.

3 **Q. What are the components of the annual ASC 715 retiree health care and life insurance**
4 **expense?**

5 A. There are four components of the annual ASC 715 retiree health care and life insurance
6 expense: (i) service cost; (ii) interest cost; (iii) expected earnings on plan assets; and
7 (iv) amortization of gains and losses, prior service costs or credits, and any transitional
8 amounts. Service cost represents one year's expected benefits earned by active covered
9 employees. Interest cost represents interest on the plan's benefit obligation (its liabilities)
10 due to the passage of time. There is also an assumption made for the expected rate of return
11 on plan assets. This rate of return assumption is intended to be a long-term assumption
12 based upon the best estimate of long-term expected investment earnings of the plan assets.
13 The last component represents amortization of various plan experiences that were not
14 anticipated by the actuarial assumptions.

15 In order to calculate the plan's total benefit obligation and annual ASC 715 retiree
16 health care and life insurance expense, the actuary uses a number of assumptions including
17 health care inflation trend rates, mortality table, the rate of employee retirements from the
18 Company, the actual retiree health care and life insurance claims of the Company, a
19 discount rate, and the expected contributions to the plan. The methods used to set
20 assumptions are generally consistent, while the values of each assumption are determined
21 by the Company each year and reviewed by the Company's auditors and actuary. The
22 method used to set the discount rate and expected return on plan assets is the same as the
23 method used for the pension plans, as discussed above.

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1 **Q. Are actuarial and administrative expenses included in Exhibit A-97 (KKG-1), page 1,**
2 **line 5?**

3 A. Yes. An annual expense for the actuarial and administrative services provided for the
4 retiree health care and life insurance plans is included in Exhibit A-97 (KKG-1), page 1,
5 line 5.

6 **Q. What changes were made to the 2024 retiree health care plans?**

7 A. In 2024, changes were made to decrease premiums in the Aetna Traditional Medical Plan
8 for Retirees.

9 **Q. What changes were made to the 2025 retiree health care plans?**

10 A. Effective January 1, 2025, current Salaried and Retirees (Exempt/Non-Exempt who are
11 under age 65 as of January 1, 2025 and Spouses, Dependents and Survivors under age 65
12 were moved to the Via Benefits Health Insurance Marketplace (also known as the
13 Individual and Family Plan Marketplace) and will no longer be eligible for coverage in the
14 Blue Cross Blue Shield of Michigan/Express Scripts and Delta Dental retiree group
15 healthcare plans.

16 **Q. Do the calculations for the retiree health care and life insurance expense follow the**
17 **prescribed methodology of ASC 715?**

18 A. Yes. The amounts are projected based on ASC 715 using information specific to the
19 Company's retiree health care and life insurance plans. For this electric rate case, the
20 OPEB Plan was measured in January 2025 for year-end.

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1 **Q. Has the Company applied the ASU No. 2017-07 Improving the Presentation of Net**
2 **Periodic Pension/OPEB Costs Standard in this case for OPEB?**

3 A. Yes, the Company adopted the ASU No. 2017-07 as of January 1, 2017, and has applied
4 the Standard in this case for both Pension and OPEB.

5 **Q. Please describe the development of the retiree health care and life insurance expense**
6 **levels that are shown on Exhibit A-97 (KKG-1), line 5, which begins with**
7 **(\$47,536,000) in 2024.**

8 A. The retiree health care and life insurance O&M expense level shown on line 5 for the
9 electric utility is based upon Aon's actuarial determination of the plan's expense for that
10 period in accordance with ASC 715 plus the cost for actuarial and administrative services
11 related to these plans. Due to the retiree medical plan changes described earlier, the actual
12 2024 retiree health care and life insurance O&M expense for the electric utility was
13 (\$47,536,000). The projected electric O&M retiree health care and life insurance expense
14 is (\$48,867,000) for the test year. Exhibit A-97 (KKG-1), page 2, line 5, column (i),
15 compares the Aon actual calculation of expense with the 2024 actual expense, as adjusted
16 for 2025, 2026, and 2027 inflation, to calculate other adjustments.

17 **Q. Why is the retiree health care and life insurance expense higher in 2024 and**
18 **decreasing in the test year?**

19 A. 2024 had lower-than-expected asset returns, which caused the lower projected expense,
20 offset decrease in expense by the plan change benefit of moving current salaried and
21 retirees (Exempt/Non-Exempt in the OPEB plan to VIA benefits in the test year.

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1 **Q. Would you please explain your Exhibit A-97 (KKG-1), page 1, line 6, for Other**
2 **Benefits, which begins with \$2,601,000 in 2024?**

3 A. Exhibit A-97 (KKG-1), line 6, reflects the actual 2024 and projected 12-month period
4 ending April 30, 2027 expenses for the electric utility benefits labor, the absence
5 management program, the educational assistance program, and the employee assistance
6 program. The adjustment in Exhibit A-97 (KKG-1), page 2, line 6, column (i), compares
7 the projected test-year expense with the 2024 actual expense, adjusted for 2025, 2026, and
8 2027 inflation.

9 **Q. Please explain why the absence management program is important to attract and**
10 **retain employees.**

11 A. Paid sick leave is needed to attract and retain employees. In 2014, the Company retained
12 Reed Group, now known as Alight, as an external consultant to manage the Company's
13 absence process. Since the relationship's inception, Alight has been able to improve the
14 absence rate and provide a higher level of standardization, controls, and overall best
15 practices to mitigate risk. Additionally, this streamlined approach ensures a procedure for
16 all employees who need a leave of absence for any purpose.

17 **Q. Please explain why the educational assistance program is important to attract and**
18 **retain employees.**

19 A. Educational assistance programs are widely available from Michigan employers as well as
20 from other utility company employers that Consumers Energy competes with for employee
21 talent. The Company offers partial tuition reimbursement to all employees. It is necessary
22 to continue providing this highly visible, competitive benefit to employees of Consumers
23 Energy to continue attracting and retaining competent employees needed by the Company,

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1 particularly considering the large number of retirement-eligible employees at the Company.
2 Attracting qualified employees and retaining this talent maximizes the efficiency of the
3 Company's labor force and reduces costly turnover. Safe, reliable, and affordable electric
4 service begins and ends with the Company's people. Investing in and retaining trained,
5 experienced, and motivated employees benefits customers as much as, or more than, any
6 investment in infrastructure. Educational assistance is just such an investment. It provides
7 the opportunity for employees to continue their education, which further improves their
8 skills to serve the customers of the Company.

9 **Q. Please explain why the employee assistance program is important to attract and retain**
10 **employees.**

11 A. The Company offers employees, retirees, and dependents access to an assistance program
12 which provides support to help resolve or manage problems that interfere with the ability
13 to perform at work or in life. The employee assistance program provides a variety of
14 on-line tools, face-to-face interactions, and telephone support. The program is designed to
15 aid with any type of need, distraction, concern, or crisis. The employee assistance program
16 provides legal support, financial information, work-life solutions, online services, and
17 confidential counseling. The goal of the program is to improve the overall total well-being
18 for all the Company's employees and retirees.

19 **Q. Does this conclude your direct testimony?**

20 A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

QUENTIN A. GUINN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

QUENTIN A. GUINN
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1 **Q. Please state your name and business address.**

2 A. My name is Quentin A. Guinn and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
6 as Capital Asset Strategy Manager.

7 **Q. What are your responsibilities as Capital Asset Strategy Manager for Consumers**
8 **Energy?**

9 A. As Capital Asset Strategy Manager, I am responsible for providing support and direction
10 for Facilities strategy development, compliance, resource planning, and regulatory
11 proceedings. The Facilities execution plan ranges from activities related to electric
12 operations to those involving corporate operational areas of Consumers Energy. Facilities’
13 asset portfolio consists of over 60 buildings and includes the corporate office, storerooms,
14 distribution centers, maintenance garages, service centers, welding and fusion workshops,
15 learning and development buildings, coal generation, wind generation, gas compression,
16 and hydroelectric sites. My responsibilities include regulatory compliance, rate case
17 strategy and execution, corporate policy administration, organizational vision, and resource
18 planning for field execution. I also provide oversight to Fleet Acquisition supporting the
19 Company’s current and long-term capital replacement strategy, vehicle disposition,
20 licensing, rentals, and internal electric vehicle (“EV”) strategy. Finally, I provide oversight
21 to the Company’s Investment Recovery Center (“IRC”) function, which handles the
22 disposition of surplus Company assets.

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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 Capital Asset Strategy Manager.

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 Electric business portion of Facility Operations and to support the Company's costs related to the electric business portion of Fleet services. To that end, I will:

- Describe the Facilities and Shared Services function;
- Describe the methodology employed by Facility Operations ("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, 2024, the bridge period beginning January 1, 2025 and ending April 30, 2026, and the projected test year ending April 30, 2027;

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- Support the reasonableness and prudence of the Operation and Maintenance (“O&M”) expenses for Facilities and Shared Services for the historical year ended December 31, 2024, the bridge period beginning January 1, 2025 and ending April 30, 2026, and the projected test year ending April 30, 2027;
- Describe the Company’s Fleet and how it is managed through Fleet Services;
- Explain the Company’s Fleet Replacement Planning Process;
- Explain the Company’s Fleet Electrification Strategy; and
- Sponsor the Company’s Fleet capital spending projections.

Q. Have you previously testified before the Michigan Public Service Commission (“MPSC” or “the Commission”)?

A. Yes. I have provided testimony on behalf of Consumers Energy in Case Nos. U-21148, U-21224, U-21308, U-21389, U-21490, U-21585, and U-21806.

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 Facilities & Shared Services and Fleet Services;

Exhibit A-101 (QAG-2)		Summary of Actual and Projected O&M Expenses Facilities & Shared Services;

Exhibit A-102 (QAG-3)		Detailed List of Projected Electric Capital Expenditures Facilities & Shared Services;

Exhibit A-103 (QAG-4)		Fleet Responsibility Costs;

Exhibit A-104 (QAG-5)		Detailed List of Projected Electric Capital Expenditures Fleet Services for the Years 2024, 2025, 2026 and test year 12 months ending April 30, 2027;

Exhibit A-105 (QAG-6)		Summary of Fleet Tooling Actual & Projected Capital Expenditures; and

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Exhibit A-106 (QAG-7)

New Construction & Renovations
Plan Summaries.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. Please describe the exhibits you are sponsoring.

A. Exhibit A-12 (QAG-1), Schedule B-5.6, details the actual and projected capital expenditures related to Facilities and Shared Services and for Fleet Services for the calendar year 2024, bridge period (16 months ending April 30, 2026), and the projected test year 12 months ending April 30, 2027. Exhibit A-101 (QAG-2) details the O&M costs related to Facilities and Shared Services. Exhibit A-102 (QAG-3) identifies Facilities and Shared Services projects and the projected capital expenditures related to those projects and programs. Exhibit A-103 (QAG-4) provides details of the Company's fleet responsibility dollars. Exhibit A-104 (QAG-5) provides details of the Company's Fleet acquisitions in the historical year 2024, bridge period (16 months ending April 30, 2026), and the projected test year 12 months ending April 30, 2027. Exhibit A-105 (QAG-6) is a Summary of Actual and Projected Fleet Tool Capital Expenditures for the historical year 2024, bridge period (16 months ending April 30, 2026), and the projected test year 12 months ending April 30, 2027. Exhibit A-106 (QAG-7) includes building assessments for the service center projects (Lansing, Hastings, Kalamazoo) and summary project schedules for all New Construction and Renovations projects included in this case.

Q. Please explain the Facilities and Shared Services function.

A. The Facilities and Shared Services function consists of the following support organizations: Fleet Services, Facilities, Real Estate, Contractor Oversight, and Supply Chain Materials Management. Facilities and Shared Services acquires, constructs, and maintains assets

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1 required to support the functional areas of the business that serve the Company's
2 customers.

3 **Q. Are you addressing all support organizations related to Facilities and Shared Services**
4 **in your direct testimony and exhibits?**

5 A. Yes.

6 **Q. What is the function of the Facilities organization?**

7 A. Within Facilities and Shared Services, Facilities manages, maintains, and operates over
8 60 buildings comprising 3.2 million square feet of building space across the state of
9 Michigan that allows the Company to serve customers across the state in an efficient and
10 effective manner.

11 **Q. How have Company facilities changed over time?**

12 A. The Company experienced major growth in the area of Facilities during the 1950s and
13 1960s. Of its 60 buildings, nearly half were built or acquired during this period and remain
14 in operation today. As a result, these buildings are now over 50 years old. The Company
15 made no significant investment in its facilities and initiated no major renovations or
16 construction of new buildings between 1970 and 2000 given competing customer
17 investment priorities. In 2003, the Company constructed its One Energy Plaza
18 headquarters building in Jackson. This construction marked the adoption of the open office
19 concept (i.e. fewer hard wall offices) at the Company which, among other reasons, was
20 adopted to foster a more collaborative work environment. Between 2000 and 2016, the
21 Company also closed many facilities including 22 service centers across Michigan to adapt
22 to shifting population trends in the state and to reduce costs for customers.

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1 **Q. What structural concerns or problems do these aging structures and facilities create**
2 **for the Company?**

3 A. Multiple major systems throughout these facilities, such as boilers, chillers, cranes,
4 elevators, emergency generators, heating, ventilation, and air conditioning (“HVAC”)
5 systems, lighting, power distribution, paving, roofing, Uninterruptible Power Systems, and
6 vehicle hoists are beyond their useful lives. Further, building materials in some facilities
7 contain hazards such as asbestos and lead paint. Repairs on such aging infrastructure are
8 not always cost effective and can lead to lengthy projects and significant renovation or
9 replacement of entire structures. It is also increasingly difficult to identify and obtain
10 adequate parts and to further locate the necessary expertise to work on aging equipment.
11 In addition, these facilities were not designed to meet modern standards of energy
12 efficiency.

13 **Q. What concerns or problems do these aging structures and facilities create for the**
14 **Company’s customers?**

15 A. The population and infrastructure of the state of Michigan look much different than they
16 did in the 1950s and 1960s. In 1950, the population of Michigan was 6,407,000 with
17 growth focused in urban areas. The state’s current population is now over 10 million, with
18 much of the growth since the 1960s having occurred in suburban areas. The locations of
19 some of the Company’s facilities no longer allow the Company to optimize service to
20 customers. In these situations, longer response times and increased drive times make
21 meeting service delivery standards difficult for the Company’s employees who are
22 dedicated to providing the best service to Consumers Energy’s customers. The cost
23 implications of these issues include but are not limited to higher transportation fuel costs,

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1 accelerated wear and tear on vehicles, and reduced cycle time for truck rolls - all of which
2 increase service costs to customers. This issue is particularly pronounced at the Lansing
3 Service Center, as I will discuss in detail later in my testimony.

4 **Q. What process does Consumers Energy utilize to evaluate whether to make capital**
5 **investments in facilities?**

6 A. The Company has been using a formal assessment process for several years that evaluates
7 whether or not to invest in a facility by studying each facility's overall health beyond
8 annual O&M expense. The Company plans to continue using this process and is enhancing
9 it by incorporating the operational priorities of the Facilities organization's internal
10 business partners (e.g., Electric Operations, Gas Engineering, etc.). Given the evolving
11 nature of the workforce (i.e. with hybrid work) the Company is working to ensure its
12 facilities are right sized and properly configured for the needs of the work.

13 **Q. What is the formal assessment process related to facility health?**

14 A. A formal assessment process was established in 2016 to determine the need for capital
15 investments in facilities. The assessment process is re-evaluated every two years resulting
16 in minor updates to the methodology to reduce subjectivity in scoring. The most recent
17 assessment was completed in 2022. The Facilities Department consists of qualified,
18 trained, and certified experts in architecture, HVAC, plumbing, and electrical that conduct
19 the assessment. In that process, an evaluation is made, on a multi-category scale, of certain
20 conditions and characteristics of the structure and functions of the facility being assessed.
21 For each facility, each condition and characteristic is scored (with a score of 0 lowest to
22 5 highest per category), and then the facility is ranked on a multi-category scale (with an
23 80-point maximum score).

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1 **Q. What categories are included in the evaluation process of the Company’s facilities?**

2 A. Categories that are evaluated include: (i) safety (such as asbestos or other hazardous
3 materials, traffic flow, and compatibility with surrounding areas); (ii) quality (such as
4 workplace efficiency, employee comfort, and talent attraction and retention); (iii) cost
5 (such as facility operating costs, space optimization, and energy efficiency); (iv) delivery
6 (such as response times, driving distance within service territory, and sustainability of
7 operations); and (v) morale (such as employee pride, wellness, and retention).

8 **Q. How is the quality of each category identified above established?**

9 A. The facility evaluated will fall within one of three quality designation categories depending
10 on the score received. A score above 64 is designated as “Good”; a score of 48 to 64 is
11 designated as “Serviceable,” meaning that investment and/or replacement is needed; and a
12 score under 48 is designated as “Poor,” meaning that there are multiple systems failing at
13 the facility. Facilities designated as “Poor” are typically candidates for replacement.

14 **Q. What is the next step in the facility assessment?**

15 A. Once the facility is initially evaluated and receives a quality designation, operational
16 departments of the business then review and validate the raw scored ranking and adjust the
17 ranking to reflect forecasted needs of the business. Facilities finalizes the score, and any
18 facility that scores below a minimum acceptable level, 48 out of 80 points, may be a
19 candidate for renovation or replacement.

1 **Q. How does the Facilities organization consider the business needs of its internal**
2 **business partners when selecting locations to target and how do facility health**
3 **assessments and evaluations of business partner needs combine to create a**
4 **prioritization plan for Facilities work?**

5 A. The Facilities organization considers business partner needs by meeting on a regular basis
6 with business partners to review their business plans and the resulting impacts on the
7 facilities necessary to support these plans. The process begins with a 10 Year Long Term
8 Facilities Plan. This plan is maintained by the Facilities organization and contains
9 fundamental information about each facility such as the year the building was constructed,
10 estimated years of useful life remaining in the building, dates of major milestones in the
11 life of the building (e.g. significant renovations and building additions), etc. The 10 Year
12 Long Term Facilities Plan is one of several inputs then used to inform creation of the
13 Long-Term Financial Plan ("LTFP"). The LTFP is a five-year financial plan created in
14 part from the aforementioned facility health assessments. Facilities organization engineers
15 and other technical experts across the Company (e.g. Company environmental analysts)
16 generate health assessments and develop capital investment priorities based on the health
17 assessments (e.g. replacement of specific assets at specific buildings, preventive
18 maintenance of specific building systems, work on a building envelope). These capital
19 investment priorities are then reviewed by business partners for alignment with their
20 business plans and can become projects incorporated into the LTFP. The ultimate list of
21 capital investment projects incorporated into the LTFP is then derived from this
22 collaboration between the Facilities organization and business partners. While considerable
23 engineering rigor is applied to developing the facility health assessments, business partner

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1 priorities do affect the ultimate list of projects incorporated into the LTFP. The Kalamazoo
2 Service Center Project included in this rate case, for instance, was elevated in priority to
3 address negative employee morale and hazardous material issues, among other factors, that
4 resulted in nearly 40% of the Kalamazoo Service Center being closed to employees.

5 **Q. Does this process ensure priority is given to Facilities projects critical to ensuring the**
6 **Company can serve its customers?**

7 A. Yes. The facility health assessments and aforementioned planning process produces a
8 prioritized list of facilities for renovation or replacement that is aligned with both the need
9 to preserve and maintain facilities assets and support business plans in providing optimal
10 customer service. Buildings that are in poor shape or are otherwise suboptimal negatively
11 impact the Company's ability to serve customers.

12 **Q. Are there situations in which prioritization of projects might change even after**
13 **development of the LTFP?**

14 A. Yes. Though not typical, reprioritization of projects after establishment of the LTFP can
15 occur. For example, several years ago the Company reprioritized development of a service
16 center in Tawas to provide timely support to customers in the greater Tawas region and to
17 reduce the workload impact on local first responders during response to emergency utility
18 events. In another example, the Company revised its plans for the Kalamazoo Service
19 Center Project included in this case. In this instance, after examining the impacts of the
20 COVID pandemic on the workforce and changes the pandemic wrought in how work is
21 performed, the Company revised its original plan to replace the Kalamazoo Service Center
22 and instead decided to renovate portions of it as many of the building modifications

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originally proposed became more costly due to supply chain 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 continues to monitor use of its facilities in a post-COVID work environment. Following the pandemic, the Company established expectations for in-person work for all employees at Company facilities. As a result, Company facilities are continuously evaluated for alignment with current and anticipated work trends. In cases where underutilized workspace has been identified, the Company has divested or examined divesting such space. For example, in 2020, the Company terminated lease agreements for over 30,000 square feet of previously leased office space at the Commonwealth Commerce Center in Jackson. The Company will continue to evaluate space utilization with the goal of eliminating underutilized space and aligning business needs with space requirements.

Capital Spending Overview

Q. What programs are included in the projected capital expenditures for Facilities?

A. As demonstrated in Exhibit A-12 (QAG-1), Schedule B-5.6, Facilities capital spending is divided into two programs: (i) Asset Preservation; and (ii) Other Equipment. Capital spending is broken down into multiple standard cost categories, including contractor, labor, materials, business expenses, and other (loadings, chargebacks). Most Facilities capital spending, as reflected in Exhibit A-12 (QAG-1), Schedule B-5.6, is for Asset Preservation, which is broken down into four portfolio categories: emergent repairs, asset replacement, new construction, and renovations.

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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 tools and equipment; Supply Chain tools and equipment; and Facilities tools. As shown in Exhibit A-12 (QAG-1), Schedule B-5.6, the Company is projecting to spend \$838,000 on Other Equipment in the bridge period and \$670,000 on Other Equipment in the 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 Facilities and Shared Services 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 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. Investment levels for Other Equipment are established annually as part of the annual budget setting process. Levels of investment are set to meet identified needs of the business.

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-102 (QAG-3), the Company is projecting to spend \$1,344,000 in the bridge period and \$2,706,000 in the 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 spending on unplanned corrective maintenance and break fix repair of assets.

Asset Replacement

Q. What capital expenditures are included in the Asset Replacements portfolio category?

A. The Asset Replacements portfolio category includes capital replacement of paved surfaces such as parking lots and driveways; roofing; mechanical and electrical equipment in buildings, and furniture. Exhibit A-102 (QAG-3) shows the Asset Replacement portfolio category broken down across the different types of work. As shown in Exhibit A-102 (QAG-3), the Company is projecting to spend \$6,563,000 on Asset Replacements in the bridge period and \$8,810,000 on Asset Replacements in the 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, along with input provided by external industry professionals. 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.

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Those assets assessed to be below acceptable condition are targeted for renovation or replacement.

Q. How does the Company identify locations for paving projects?

A. The condition of paving assets is evaluated following standard industry practices on a rolling five-year basis with a condition assessment performed annually for 20% of Company sites. Paving assets are prioritized for replacement based on the lowest assessed condition index score. Paving projects may include other related enhancements to paved surfaces such as new drainage or new lighting.

Q. How did the Company determine the amount of needed investment in paving projects for the bridge period and the test year?

A. The total amount of needed investment in paving projects begins with the five-year historical average spend. Paving condition assessments are then used to determine how that spend is allocated. While investment in paving projects may be greater than or less than the five-year historical average spend in a given year, total Asset Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

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.

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1 **Q. How did the Company determine the amount of needed investment in roofing projects**
2 **for the bridge period and the test year?**

3 A. The total amount of needed investment in roofing projects begins with the five-year
4 historical average spend. Roofing condition assessments are then used to determine how
5 that spend is allocated. While investment in roofing projects may be greater than or less
6 than the five-year historical average spend in a given year, total Asset Replacement
7 investment is maintained at or below the five-year historical average spend for Asset
8 Replacement.

9 **Q. How does the Company identify locations for mechanical and electrical projects?**

10 A. The condition of mechanical and electrical assets is evaluated by Facilities engineers for
11 all Company sites. Based on the results of these evaluations, targeted maintenance work
12 is performed on mechanical and electrical assets. Where the condition of mechanical and
13 electrical assets is determined to be below an acceptable threshold for targeted repair or
14 maintenance, the mechanical and electrical assets are prioritized for replacement based on
15 the results of these evaluations.

16 **Q. How did the Company determine the amount of needed investment in mechanical and**
17 **electrical projects for the bridge period and the test year?**

18 A. The total amount of needed investment in mechanical and electrical projects begins with
19 the five-year historical average spend. Mechanical and electrical condition assessments
20 are then used to determine how that spend is allocated. While investment in mechanical
21 and electrical projects may be greater than or less than the five-year historical average
22 spend in a given year, total Asset Replacement investment is maintained at or below the
23 five-year historical average spend for Asset Replacement.

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1 **Q. How does the Company identify locations for elevator projects?**

2 A. The condition of elevator assets for all Company sites are evaluated by outside consultants
3 and subject matter experts. Elevator assets are prioritized for replacement based on the
4 results of these evaluations utilizing a condition assessment score of 1 to 5. Elevators with
5 an assessment score of 3 or below are targeted for modernization or replacement.

6 **Q. How did the Company determine the amount of needed investment in elevator**
7 **projects for the bridge period and the test year?**

8 A. The total amount of needed investment in elevator projects begins with the five-year
9 historical average spend. Elevator condition assessments are then used to determine how
10 that spend is allocated. While investment in elevator projects may be greater than or less
11 than the five-year historical average spend in a given year, total Asset Replacement
12 investment is maintained at or below the five-year historical average spend for Asset
13 Replacement.

14 **Q. How does the Company identify where furniture replacements are needed?**

15 A. Furniture replacement is determined based on business need. Subject matter experts
16 evaluate business unit requirements and existing furniture. Where the existing furniture
17 does not meet business unit requirements, the furniture is identified for replacement.

18 **Q. How did the Company determine the amount of needed investment in furniture for**
19 **the bridge period and the test year?**

20 A. The total amount of needed investment in furniture begins with the five-year historical
21 average spend. The needs of the business are then assessed and those assessments are used
22 to determine how that spend is allocated. While investment in furniture may be greater
23 than or less than the five-year historical average spend in a given year, total Asset

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Replacement investment is maintained at or below the five-year historical average spend for Asset Replacement.

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. In accordance with the Order in Case No. U-21585, the Company in this case will not seek an allowance for its Lansing Service Center Project nor its Hastings Service Center Project in the New Construction category. See Exhibit A-102 (QAG-3). The Company will seek an allowance for these projects when it demonstrates substantial progress on each respective project. In this testimony, the Company will provide information concerning these projects and the status of each respective project.

Q. Does the Company consider environmental impacts when planning for new construction?

A. Yes. New buildings incorporate the United States Green Building Council (“USGBC”) standards (see usgbc.org), and the Leadership in Energy and Environmental Design (“LEED”) standards (see usgbc.org/leed), with specific emphasis on reduced energy consumption, sustainability, and reduced operating cost.

Q. Do these environmental building standards benefit the Company’s customers?

A. Yes. When compared to conventional construction, buildings designed to LEED standards reduce lifetime energy consumption by 30% or more, resulting in reduced operational costs which allow customers to pay less for utility costs. In addition, new buildings require less maintenance and are easier to maintain than an aged structure, resulting in an estimated 5%

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1 cost reduction. Consumers Energy's recently constructed Coldwater Service Center was
2 designed and built to these standards.

3 **Q. Describe the Lansing Service Center project. What is its overall goal?**

4 A. In this project, the Company has purchased land in a new location and will construct a new
5 facility on that property. This facility will allow the Company to retire its existing facility
6 (which will be demolished and retained to address and abate environmental concerns
7 resulting from the operation of a former Manufactured Gas Plant ("MGP") on the site).
8 This new facility will house many employees currently working out of the existing service
9 center. The Company anticipates a portion of these employees will have a hybrid work
10 arrangement in which the employees perform some work tasks at the Lansing Service
11 Center and some work tasks elsewhere including their homes. Employees with a hybrid
12 work arrangement will require collaborative space and open office space in the facility
13 when they are on-site to work with other personnel.

14 **Q. What alternatives to the construction of a new Lansing Service Center did the**
15 **Company consider?**

16 A. The Company considered the following three alternatives: (1) Do nothing; (2) Renovate
17 the existing Lansing Service Center; (3) Demolish the existing building and construct a
18 new building on site; and (4) Construct a new facility at a new location, with multiple
19 locations considered. The option to construct a new facility at a new location was
20 determined optimal for the reasons noted below.

21 **Q. Why has the Company chosen to build a new Lansing Service Center?**

22 A. As demonstrated in Exhibit A-106 (QAG-7), a Facilities assessment of the existing Lansing
23 Service Center produced a score of 39, placing the existing Lansing Service Center in the

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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 located 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, and stray shooting incidents. 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-106 (QAG-7), 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

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1 and due to the location, does not allow Electric Operations to meet customer needs in a
2 timely fashion. Further, the roads (because of the residential zoning) are inadequate for
3 the size of equipment utilized in and out of the service center and there are often children
4 in the vicinity, which creates significant safety concerns. The current site is also located
5 within the floodplain of the Grand River with the finish floor elevation located three feet
6 below the major flooding elevation projected by the Federal Emergency Management
7 Agency. All these considerations negatively impact the Company's ability to dispatch both
8 personnel and equipment to serve customers. Other considerations supporting the decision
9 to construct a new facility, rather than renovate the existing facility, include operating cost
10 reductions, security, and environmental abatement. Because of all of these factors, the
11 Company has decided to build a new Lansing Service Center at a new location.

12 **Q. Can you elaborate further on the security and environmental abatement issues at the**
13 **Lansing Service Center?**

14 A. Yes. The site has experienced multiple law enforcement incidents. These incidents have
15 resulted in lock-down safety protocol implementation for employees and a resulting
16 general level of unease regarding the safety and security of employees, customers, and
17 others, while on the property and when accessing or leaving the property. Environmental
18 issues arise from the former use of the current Lansing Service Center site as the location
19 of a former MGP regulated under Public Act 451 of 1994, Part 201. This site has historical
20 environmental contamination issues resulting from operation of the MGP, including
21 significant underground impacted soil materials (i.e. coal tar residual). Additionally, the
22 facility contains asbestos insulation for pipe and duct work, asbestos flooring, and has
23 significant areas of lead paint in poor and peeling condition. Given these environmental

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1 issues, upgrades to the facility (e.g. carpet replacement and open space enhancement)
2 cannot be cost effectively completed.

3 **Q. Has the Company engaged in an environmental study for the area selected for the**
4 **new Lansing Service Center?**

5 A. Yes. The site for the Lansing Service Center includes previous agricultural use; thus, no
6 environmental impacts exist from this previous use. A Phase 1 Environmental investigation
7 has been completed. The site contains wetland areas and the Company is leaving these
8 wetland areas undisturbed. A wetland assessment has also been completed.

9 **Q. What energy efficiency and waste reduction measures does the Company plan to**
10 **install at the new Lansing Service Center?**

11 A. The new Lansing Service Center facility is planned to be designed and constructed to
12 achieve certification under the USGBC, LEED version 4 rating system.

13 **Q. The Lansing Service Center project includes the relocation of that facility to a**
14 **different part of the Lansing metropolitan area. Can you explain what is considered**
15 **generally when considering relocation of a facility?**

16 A. Yes. As noted earlier, Company facilities are assessed and scored based on multiple
17 criteria (i.e., safety, quality, cost, delivery, and morale) to provide a holistic score that
18 informs the Company of the possible need to make improvements. Facilities with scores
19 falling below the acceptable range are targeted for renovation or replacement. Part of the
20 overall analysis, which is relevant to the Lansing Service Center, is the geographic location
21 of targeted facilities. Geographic locations are analyzed against customer workload
22 distribution within the service territory to determine optimal location for the facility.
23 Facilities that are determined to be mis-located within the customer service territory are

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1 evaluated for relocation to a newly constructed site with the goal of improved customer
2 response. Facilities determined to already be optimally located within the customer service
3 territory are evaluated for renovation or reconstruction on the existing site.

4 **Q. How did the Company determine a new location for the Lansing Service Center?**

5 A. An analysis of customer distribution across the service territory where the Lansing Service
6 Center is located, and potential service center locations within that service territory,
7 determined the optimal area to minimize response times. This analysis is reflected in
8 Exhibit A-106 (QAG-7). Reducing customer response times lowers fuel costs by
9 minimizing the distance Company employees must travel to job sites. Determining the
10 optimal area to minimize response times also maximizes employee efficiency by reducing
11 labor hours required to reach and service customers. The current location of the Lansing
12 Service Center is offset to the north and east of the optimal location, in a residentially zoned
13 neighborhood, and the current location does not provide readily available highway access.
14 The current location of the Lansing Service Center within the service territory results in
15 increased customer response times, higher fuel costs, and reduced employee efficiency due
16 to increased travel times as explained above. The location for the new Lansing Service
17 Center will not only be in a more appropriately zoned area but will also provide improved
18 customer response times.

19 **Q. Has land been acquired for the Lansing Service Center? If so, please identify the**
20 **location of the land.**

21 A. Yes. Land was acquired for the Lansing Service Center in December 2020, located in
22 Windsor Charter Township, at the southeast corner of the intersection of Canal Road and
23 Billwood Highway, Dimondale, Michigan 48821.

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1 **Q. What type of operations departments will work at the new Lansing Service Center as**
2 **compared to the existing Lansing Service Center?**

3 A. The existing Lansing Service Center houses the following operations: Customer
4 Experience; Gas Operations; Enterprise Project Management/Environmental Services; Gas
5 Engineering & Supply; Generation Operations & Compression; Information Technology
6 (“IT”); Electric Operations; Operations Performance; Shared Services; and People &
7 Culture. The Company anticipates personnel from some (not all) of these operating groups
8 to be housed in the new Lansing Service Center. Because the new facility is being
9 constructed to better serve the Company’s customers in the Lansing area, only Company
10 personnel dedicated to servicing these customers will be housed in the new Lansing Service
11 Center.

12 **Q. Approximately how many employees will work at the new Lansing Service Center as**
13 **compared to the existing Lansing Service Center?**

14 A. Approximately 450 employees are assigned to the existing Lansing Service Center. The
15 Company anticipates the new Lansing Service Center will house approximately 450
16 employees with some adaptation in their use of the workspace including some employees
17 adopting a hybrid work arrangement, requiring only collaborative space and transient
18 shared office space in the facility when they are on-site to work with other personnel.

19 **Q. What is the status of the Lansing Service Center project at the time of this filing?**
20 **What work has been completed so far, and what work is still remaining to be done?**

21 A. Land acquisition and rezoning of the parcel in Dimondale has been completed. Design
22 engineering and bidding have been completed and a contract awarded for a municipal water
23 main extension to the project site. The water main extension is fully constructed.

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1 A design-build contract for construction management services has been competitively bid
2 and awarded. Programming of the building is complete and architectural design of the
3 building will be complete before the second quarter of 2025. The Company intends to
4 begin construction of the facility in the third quarter of 2025. See Exhibit A-106 (QAG-7).

5 **Q. How much did the Company invest in the Lansing Service Center project in the 2024**
6 **historical year in this case?**

7 A. In the 2024 historical year in this case, the Company invested \$2,170,000 in this project.
8 See Exhibit A-102 (QAG-3).

9 **Q. Please describe the Hastings Service Center project. What is its overall goal?**

10 A. The Company is planning to construct a new Hastings Service Center at the existing service
11 center location to include an adjacent property the Company is negotiating to purchase
12 from the adjacent landowner. This new facility will house most employees currently
13 working at the existing service center. A portion of the employees currently working at
14 the existing service center will have a hybrid work arrangement and will require only
15 collaborative space and transient shared office space in the facility when they are on-site
16 to work with other personnel.

17 **Q. What alternatives to the construction of a new Hastings Service Center did the**
18 **Company consider?**

19 A. The Company considered four alternatives: (1) Do nothing; (2) Renovate the existing
20 Hastings Service Center; (3) Demolish the existing building and construct a new building
21 on site; and (4) Construct a new facility at a new site. The options to either demolish the
22 existing building and construct a new building on site or demolish the existing building

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1 and construct a new building at a larger site were identified as optimal depending on
2 availability of suitable land.

3 **Q. Why has the Company chosen to construct a new Hastings Service Center facility?**

4 A. As demonstrated in Exhibit A-106 (QAG-7), a Facilities assessment of the existing
5 Hastings Service Center produced a score of 41. As discussed above, because this score
6 falls below a score of 48, it was targeted for replacement, and the “do nothing” option was
7 ruled out. For the same reason that the Lansing Service Center was targeted for
8 replacement, including aging infrastructure, which is beyond useful life, the Hastings
9 Service Center was determined to need replacement. The current site is fully developed
10 and is no longer sufficient to support ongoing utility operations as the site lacks adequate
11 space for both safe vehicle maneuvering and utility construction material storage. In
12 addition, the existing building envelope does not comply with current energy code
13 requirements. The Facilities organization, therefore, ruled out the renovation option for
14 the Hastings Service Center. The existing Hastings Service Center site is located within
15 an industrialized area with access to major roads and highways. The Company determined
16 that the facility is currently in an optimal location to service customers (see Exhibit A-106
17 (QAG-7)). Therefore, with the acquisition of appropriate adjacent parcels, the Hastings
18 Service Center has been targeted for replacement on the existing site in lieu of relocation.
19 Other considerations supporting the decision to replace the existing site include
20 environmental abatement.

21 **Q. Can you further elaborate on how these alternatives were compared?**

22 A. The Company originally sought to construct a new facility on the existing property.
23 Construction of the new Hastings Service Center on the existing property was predicated

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1 on reaching agreement with the adjacent landowner to transfer a portion of their property
2 to Consumers Energy, which would increase the available site area for development and
3 provide enough space for the new facility. Agreement for a property transfer with an
4 adjacent landowner was initially not reached. The properties on the west and east are fully
5 developed. The Company then entered negotiations with the Barry County Road
6 Commission (owner of the adjacent parcel to the south). The Barry County Road
7 Commission approved the Company's conceptual plan for development of this parcel. The
8 Company completed acquisition of the parcel in March 2025 which will allow for
9 expansion of the existing Hastings site and construction of the new facility.

10 **Q. What energy efficiency and waste reduction measures does the Company plan to**
11 **install at the new Hastings Service Center?**

12 A. The proposed new Hastings Service Center facility is planned to be designed and
13 constructed to achieve certification under the USGBC, LEED version 4 rating system.

14 **Q. Will this building be larger or smaller than the existing Hastings Service Center?**

15 A. The conceptual site plan for the new service center is shown in Exhibit A-106 (QAG-7).
16 The original projected building area based on conceptual data assembled is larger than the
17 existing Hastings Service Center by 11,183 square feet. The new facility is designed with
18 a larger footprint to address multiple deficiencies at the existing facility that negatively
19 impact electric operations including insufficient space for crew rooms, parts and material
20 storage, welding operations, and automotive tools and repairs. Even at 23,500 square feet,
21 however, the projected building area of the new Hastings Service Center, based on
22 conceptual data, is smaller than many of the Company's Service Centers.

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1 **Q. What type of operations departments will work at the new Hastings Service Center**
2 **as compared to the existing Hastings Service Center?**

3 A. The existing Hastings Service Center houses the following operations: Gas Operations;
4 Electric Operations; Planning & Scheduling, and Shared Services. The Company
5 anticipates the new Hastings Service Center will house many of these same operations.

6 **Q. Approximately how many employees will work at the new Hastings Service Center**
7 **as compared to the existing Hastings Service Center?**

8 A. The existing Hastings Service Center houses approximately 50 employees. The Company
9 anticipates the New Hastings Service Center will house a comparable number of
10 employees.

11 **Q. What is the status of the construction of the Hastings Service Center at the time of**
12 **this filing? What work has been completed so far?**

13 A. The Barry County Road Commission (owner of the adjacent parcel to the south) has
14 approved the Company's conceptual plan for development of the parcel. A Phase 1
15 Environmental Study, a Phase 2 Environmental Study, and a Baseline Environmental
16 Assessment have been completed. The adjacent parcel to the south was acquired in March
17 2025 and programming design for the new facility has commenced.

18 **Q. How much did the Company invest in the Hastings Service Center project in the**
19 **historical year in this case?**

20 A. In the 2024 historical year in this case, the Company invested \$114,000 in this project for
21 survey and related real estate work done on the site. See Exhibit A-102 (QAG-3).

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Renovations

Q. What capital expenditures are included in the Renovations portfolio category?

A. The Renovations portfolio category includes major modifications to the interior and/or exterior of existing facilities (e.g. adding a garage to a building). As shown in Exhibit A-102 (QAG-3), the Company is projecting to spend \$15,603,000 on Renovations in the bridge period and \$15,855,000 on Renovations in the test year.

Q. Has the Company identified projects in the Renovations portfolio category?

A. Yes. As shown in Exhibit A-102 (QAG-3), the Company has identified the following Renovations projects:

- Kalamazoo Service Center
- Control/Dispatch Center – Grand Rapids
- Control/Dispatch Center - Parnall
- South Monroe Interior Renovation
- Electric Vehicle Infrastructure

In accordance with the Commission Order in Case No. U-21585, the Company in this case will not seek an allowance for its Kalamazoo Service Center Project in the Renovations category. See Exhibit A-102 (QAG-3). The Company will seek an allowance for this project when it demonstrates substantial progress on the project. In this testimony, the Company will provide information concerning this project and its status.

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 is remediating asbestos concerns, workspace concerns, and problems with aging building systems at the existing facility upon completion of this renovation. The

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renovations of this facility entail adding insulation to exterior walls, installation of new exterior doors and windows, new roofing membrane and roof insulation, new interior finishes, new furnishings, new plumbing fixtures and fittings, new HVAC equipment and ductwork, and new energy efficient lighting systems.

Q. What alternatives to the renovation of the Kalamazoo Service Center did the Company consider?

A. The Company considered the following three alternatives: (1) Do nothing; (2) Renovate the existing Kalamazoo Service Center; and (3) Demolish the existing building and construct a new building on site. The option to renovate was identified as optimal.

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 Company witness Scott J. Bartholomew testified in his direct testimony in Case No. U-20963. The Company subsequently reevaluated its plans to ensure the renovated Kalamazoo Service Center is constructed in a manner that optimizes use of capital. In Case No. U-20963, the Company's projected total cost for the renovated Kalamazoo Service Center was \$52 million. The Company's projected total cost for the renovated Kalamazoo Service Center is now \$35 million, an approximate 33% reduction in cost. The Company determined that a renovation would meet its workforce needs and provide better value for customers by minimizing the scope of architectural work required to achieve needed improvements in the facility. A renovation of the existing Kalamazoo Service Center will maximize utilization of the building's existing space, while controlling capital costs and 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

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1 where the equipment and vehicles that crews use to service customers are maintained and
2 serviced. Other considerations supporting the decision to renovate the existing facility
3 include the fact that the Kalamazoo Service Center is already optimally located for
4 responding timely to the Company's customers.

5 **Q. Why is doing nothing not a viable option at this location?**

6 A. As demonstrated in Exhibit A-106 (QAG-7), a Facilities assessment of the existing
7 Kalamazoo Service Center produced a score of 46. Since this assessment was conducted,
8 additional asbestos issues have been identified at this site (i.e. spray applied fireproofing,
9 pipe wrap, floor tiles, etc.). All employees at this site were moved to the second floor of
10 the building due to air quality issues rooted in the growth of mold and related asbestos
11 concerns on the first floor. This limited space is inadequate for the Company's Electric
12 and Gas Operations employees to operate. As discussed above, because an assessment
13 score of 46 falls below a score of 48, the Kalamazoo Service Center was originally targeted
14 for replacement. In addition to its environmental concerns, the existing Kalamazoo Service
15 Center was constructed in 1965, and its continuing use was determined inadequate due to
16 aging infrastructure. Most of the existing systems throughout the facility are over 50 years
17 old and beyond their useful lives. The space requirements of the existing workforce have
18 changed as more personnel adopt a hybrid work arrangement requiring only collaborative
19 workspace and open office space when they are in the office working collaboratively with
20 others. Finally, the existing Kalamazoo Service Center is optimally located for responding
21 timely to the Company's customers and, therefore, remaining at the current location best
22 supports the Company's intent to provide timely service to its customers in the Kalamazoo
23 area.

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1 **Q. What energy efficiency and waste reduction measures does the Company plan to**
2 **install at the renovated Kalamazoo Service Center?**

3 A. The renovated Kalamazoo Service Center is planned to be designed and constructed to
4 achieve certification under the USGBC, LEED version 4 rating system.

5 **Q. What is the status of the renovation of the Kalamazoo Service Center at the time of**
6 **this filing?**

7 A. The Company has bid and awarded a contract for construction management services and a
8 contract for architectural and engineering design services. Architectural and engineering
9 design work on the project is complete and renovation construction is underway. See
10 Exhibit A-106 (QAG-7).

11 **Q. How much did the Company invest in the Kalamazoo Service Center project during**
12 **the historical year of this case?**

13 A. The Company invested \$4,551,000 in this project during the 2024 historical year for
14 engineering and construction associated with renovation of the facility. See Exhibit A-102
15 (QAG-3).

16 **Q. Is the projected size of the renovated Kalamazoo Service Center larger or smaller**
17 **than the existing Kalamazoo Service Center?**

18 A. The size of the renovated Kalamazoo Service Center is not projected to vary significantly
19 from the size of the existing Kalamazoo Service Center because there is no anticipated
20 change in the overall footprint of the facility.

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1 **Q. What type of operations departments will work at the renovated Kalamazoo Service**
2 **Center as compared to the existing Kalamazoo Service Center?**

3 A. The existing Kalamazoo Service Center houses the following operations: Customer
4 Experience; Gas Operations; Enterprise Project Management/Environmental Services;
5 Information Technology (IT); Electric Operations; Shared Services; and Public Affairs.
6 The Company anticipates personnel from some (not all) of these operating groups to be
7 housed in the renovated Kalamazoo Service Center.

8 **Q. Approximately how many employees will work at the renovated Kalamazoo Service**
9 **Center as compared to the existing Kalamazoo Service Center?**

10 A. Approximately 250 employees are assigned to the existing Kalamazoo Service Center. The
11 Company anticipates the renovated Kalamazoo Service Center will house the majority (not
12 all) of these employees with some employees adopting a hybrid work arrangement and
13 requiring only collaborative space and transient shared office space in the facility when
14 they are on-site to work with other personnel.

15 **Q. Please describe the Control/Dispatch Center Consolidation - Parnall Project and**
16 **Control/Dispatch Center Consolidation – Grand Rapids Project. What are the**
17 **overall goals of these projects?**

18 A. A complete description of both Control/Dispatch Center Consolidation Projects and their
19 overall goals are outlined in the testimony of Company witness Andrew R. Snider. This
20 testimony is tailored very narrowly to a discussion of the building renovations that support
21 the Control/Dispatch Center Consolidation Project – Grand Rapids and the
22 Control/Dispatch Center Consolidation Project – Parnall which together comprise the

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Control/Dispatch Center Consolidation Project discussed in Company witness Snider's testimony.

Q. What benefits will the renovations constructed pursuant to the Control/Dispatch Consolidation projects provide to customers?

A. The benefits to customers of the Control/Dispatch Center Consolidation Project renovations are outlined in the testimony of Company witness Snider.

Q. How much does the Company project to invest in both Control/Dispatch Center Consolidation renovations in the bridge period and test year in this case?

A. As shown in Exhibit A-102 (QAG-3), the Company is projecting to invest a total of \$10,746,000 in Control/Dispatch Center Consolidation Project renovations in the bridge period and a total of \$15,497,000 in Control/Dispatch Center Consolidation Project renovations in the test year.

Q. How have these projected costs been derived?

A. Cost estimates were developed utilizing the conceptual plan and historical cost data from many similar projects.

Q. What is the status of the Control/Dispatch Center Consolidation Project renovations at the time of this filing?

A. The Control/Dispatch Center Consolidation Project – Grand Rapids and the Control/Dispatch Center Consolidation Project – Parnall are both in design. See Exhibit A-106 (QAG-7).

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1 **Q. Describe the South Monroe Service Center Interior Renovation Project. What is its**
2 **overall goal?**

3 A. The purpose of this project is to acquire design and engineering services needed to remodel
4 a portion of the Company's South Monroe Service Center interior. This remodel will
5 provide adequate meeting space for Company crews. The remodel will also bring the
6 facility into compliance with multiple code requirements including but not limited to the
7 Americans with Disabilities Act ("ADA") access, the number of restroom fixtures required
8 per building occupant, and ventilation required in the building's indoor parking area
9 ("IPA"). The project will include development of a building addition needed to house
10 utility construction equipment and maintenance materials such as cable ties, insulators,
11 cable splices, and switches. The size of the existing South Monroe Service Center is no
12 longer adequate to support operational needs. The workload assigned to the South Monroe
13 Service Center has increased and the number of Company crews operating from the
14 building has increased commensurately. This, in turn, has driven an increase in the amount
15 of material necessary to support work at the site and an increase in the amount of space
16 required in the building to support operational needs.

17 **Q. What alternatives did the Company consider for this project?**

18 A. The Company considered the following alternatives: (1) Do nothing; (2) perform an
19 interior renovation only; (3) perform an interior renovation and construct a building
20 addition; or (4) perform an interior renovation and acquire an adjacent building in lieu of
21 constructing a building addition. Doing nothing is not a suitable option because the
22 existing building is no longer suitable to support operational needs and must be brought
23 into compliance with several code requirements. An interior renovation only (the second

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1 alternative) would provide adequate space for crew meetings and bring the building into
2 compliance with several code requirements but is ultimately not suitable because it would
3 not address the site's need for additional storage space. An interior renovation coupled
4 with a building addition (the third alternative) and an interior renovation coupled with
5 acquiring an adjacent building (the fourth alternative) would provide adequate space for
6 crew meetings, will bring the building into compliance with minimum code requirements,
7 and will meet the site's need for additional storage space. The fourth alternative was
8 deemed optimal because the cost of acquiring an adjacent building is less than the cost of
9 building a comparable addition (the third alternative).

10 **Q. Why did the Company choose to perform this renovation?**

11 A. As noted, the South Monroe Service Center is not adequate to support the site's growing
12 workload and is currently out of compliance with several code requirements.

13 **Q. What benefits will this building provide for customers?**

14 A. The increased workload at the South Monroe Service Center is driven by an increase in the
15 pace of system reliability work the Company is performing. The Company's workforce
16 assigned to the South Monroe Service Center requires adequate storage space for materials,
17 vehicles, equipment, and crew room space to perform system reliability work. The
18 Company's customers in the South Monroe area directly benefit from fewer, shorter
19 outages that result from a more reliable and resilient electric distribution system in the area.

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1 **Q. How much does the Company project to invest in the South Monroe Service Center**
2 **Interior Renovation project in the bridge period and test year in this case?**

3 A. As shown in Exhibit A-102 (QAG-3), the Company is projecting to invest \$4,186,000 in
4 the South Monroe Service Center Interior Renovation Project in the bridge period and
5 \$86,000 in the test year.

6 **Q. How have these projected costs been derived?**

7 A. Outside consultants and contractors have been engaged to develop and prepare a design
8 program and construction schedule for the South Monroe Interior Renovation Project.
9 These firms have evaluated the design program and construction schedule to develop
10 project cost estimates.

11 **Q. What is the status of the construction of the South Monroe Service Center renovation**
12 **project at the time of this filing?**

13 A. Architectural design work is in progress and the Company has acquired a building from an
14 adjacent property owner that will be used for material and equipment storage. See Exhibit
15 A-106 (QAG-7).

16 **Q. Has the Company invested any capital in the South Monroe Service Center**
17 **renovation project so far?**

18 A. \$908,000 has been invested in the South Monroe Service Center Interior Renovation
19 Project for architectural design services and acquisition of an adjacent building. See
20 Exhibit A-102 (QAG-3).

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1 **Q. Please describe the Electric Vehicle Charging Infrastructure project. What are its**
2 **overall goals?**

3 A. As outlined in my direct testimony, the Company plans to electrify portions of its vehicle
4 fleet by purchasing EVs for Company use. The Company is currently acquiring EVs. To
5 ensure these EVs are available for Company crews to use in serving customers, the
6 Company must construct adequate charging infrastructure at sites where these vehicles will
7 be maintained.

8 **Q. How much capital is the Company projecting to invest in the Electric Vehicle**
9 **Charging Infrastructure project in the bridge period and test year in this case and**
10 **for what purpose?**

11 A. As shown in Exhibit A-102 (QAG-3), the Company is projecting to invest \$671,000 in the
12 Electric Vehicle Charging Infrastructure project in the bridge period and \$272,000 in the
13 test year. The purpose of this investment is to provide the electric infrastructure upgrades
14 and charging station installations required to support EVs purchased in the bridge period
15 and test year as outlined in my direct testimony.

16 **Q. At what buildings will EV charging infrastructure be installed during the bridge**
17 **period and test years of this case?**

18 A. The planned headquarter locations at which EV charging infrastructure will be installed
19 include Jackson, Royal Oak, Lansing, Bay City, Battle Creek, and Adrian.

20 **Q. How were these costs determined?**

21 A. Cost estimates were developed for electric infrastructure upgrades and charging station
22 installations required to support EVs purchased in the bridge period and test year utilizing
23 historical cost data from similar previous projects.

O&M Spending Overview

Q. What O&M expenses are included in “Facilities” in Exhibit A-101 (QAG-2), line 1?

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. The Company maintains data on maintenance history in its buildings. This data, in conjunction with historical spend, is used to forecast projected Facilities O&M expense growth at or below the rate of historical plus the current inflation factor year over year.

Q. What O&M expenses are included in “Real Estate” in Exhibit A-101 (QAG-2), line 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. The Company reviews its needs for real estate services annually. This information, in conjunction with historical spend, is used to forecast projected Real Estate O&M expense growth at or below the rate of historical plus the current inflation factor year over year.

FLEET SERVICES FUNCTION AND RESPONSIBILITIES

Q. What functions compose the Fleet Services organization?

A. The Fleet Services organization consists of three departments which collaboratively work together to provide value to Electric Operations in serving customers. The three departments include Fleet Maintenance Operations, Fleet Acquisition, and Shared Services Governance Performance and Technology.

Q. Are you addressing all support organizations related to Electric Operations Support in your direct testimony and exhibits?

A. Yes.

Q. Please explain the responsibilities of Fleet Maintenance Operations.

A. Fleet Maintenance Operations is responsible for maintaining a safe, cost effective, and reliable fleet. This is accomplished through preventative maintenance, regulatory inspections, parts inventory management, and maintenance scheduling across 36 garage locations with approximately 110 mechanics. Maintenance Operations also oversees mechanic contractor crews for preventative maintenance and repairs performed in the field.

Q. Please explain the responsibilities of Fleet Acquisition.

A. Fleet Acquisition executes all functions related to the acquisition and disposition of Company-owned and rented vehicles and related equipment. This includes management of the Fleet capital purchase plan, vehicle specification design, licensing/title, registration, and asset retirement.

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1 **Q. Please explain the responsibilities of Shared Services Governance Performance and**
2 **Technology department.**

3 A. Governance Performance and Technology provides fleet with support of data integrity,
4 Telematics data management (software installed in vehicles to provide information such as
5 location, speed, fuel consumption, etc.), departmental metric visual management, process
6 automation, oversight of waste elimination initiatives, and evaluates benchmarking and
7 data analysis provided to the Company. This team is also responsible for meeting all
8 regulatory and compliance requirements with the American National Standards Institute,
9 Department of Transportation, Michigan Motor Vehicle Code, and Federal Motor Carrier
10 Safety Administration. Additional responsibilities include Fleet Operations Policies and
11 Procedures, regulatory and technical support, and tooling for fleet mechanics and the
12 Company's EV strategy. The department also provides oversight for quality inspection
13 audits and safety requirements related to regulatory compliance.

14 **Q. Please explain the Company's overall fleet structure.**

15 A. The Company's fleet includes approximately 7,207 owned, leased, and rented units across
16 36 locations. These units include light duty vehicles (approximately 2,800 units), medium
17 and heavy-duty trucks (approximately 1,500 units), various types of equipment
18 (approximately 1,400 units), and trailers (approximately 1,900 units). Internally, the
19 Company categorizes its fleet into several specifications ("spec(s)"), each of which is a
20 given type, model, and description of a vehicle. Each spec has a defined intended use,
21 acquisition cost, operating cost, and expected life in years and mileage.

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1 **Q. How is the Company’s fleet divided between the electric and natural gas businesses?**

2 A. The Company divides its fleet between the electric and natural gas businesses by
3 determining which business unit at a given location is using each particular vehicle. The
4 needs of the business require the deployment of dedicated teams to safely complete work
5 utilizing specific tools and processes – this extends to the vehicle supporting said work.
6 These vehicles are ordered and upfitted to support specific work and are, therefore,
7 specialized for the work they perform; however, the Company does seek ways that units
8 can be shared across the business when possible. The fleet requirements for the location
9 will vary based on the service provided to the customer (electric, gas, or both), crew counts,
10 and region. Additionally, some Company fleet units serve both electric and gas functions
11 and are referred to as “common” units, which are utilized by support organizations, such
12 as Facilities, Fleet, and Supply Chain. Overall, the Company’s fleet is 40% electric, 50%
13 gas, and 10% common by number of vehicles.

14 **Q. What is the purpose of Fleet Services as it relates to the Company’s electric business?**

15 A. Specific to the Company’s electric business, Fleet Services’ purpose is to provide vehicles
16 and equipment that enable Electric Operations to serve customers with safe, reliable, and
17 affordable electric service. This is accomplished by ensuring that the Company’s Fleet
18 assets are available to execute the work plan and respond to emergencies in the most
19 efficient, cost-effective, and safe manner when required.

20 **Q. Does the Company’s fleet incur both capital and O&M costs?**

21 A. The Company makes direct capital investments in its fleet as provided in Exhibit A-12
22 (QAG-1), Schedule B-5.6, page 4. The Company also incurs other costs related to its fleet

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that are treated as “fleet responsibility” dollars, which in this case are presented in Exhibit A-103 (QAG-4).

Q. What are fleet responsibility dollars?

A. In addition to direct capital expenditures for fleet vehicles, tools, and other equipment, the Company also incurs other costs related to its fleet that are treated as “fleet responsibility” dollars. The Company does not have specific Fleet O&M expenses.

Fleet operating costs are reported in responsibility dollars. Each fleet unit has defined work assignments that determine which functional areas are allocated the associated responsibility dollars for the unit. Fleet responsibility costs are allocated to both capital and O&M expenses based on the work assignment performed.

Q. Please explain how fleet responsibility dollars are allocated to both capital and O&M.

A. The process for allocating fleet responsibility dollars is a multi-step process. The first step in the process is that costs associated with each fleet vehicle or piece of equipment are charged to an internal order. Each fleet vehicle/equipment has its own internal order that collects costs like fuel and maintenance, which is assigned to a department/responsibility area.

The next step is that the costs from the internal orders are moved to separate fleet clearing accounts for each department/responsibility area. The final step in the process is the allocation of the costs from the fleet clearing accounts. The costs in each clearing account are allocated to work orders or cost centers based on the labor charges for that respective department/responsibility area. Additionally, the fleet costs to be allocated are separated between labor and non-labor fleet loading.

1 **Q. Can the Company identify to which budget line items, in various parts of the business**
2 **responsibility dollars, are allocated and ultimately settled?**

3 A. No. Fleet responsibility dollars are assigned to multiple work orders and ultimately settle
4 to multiple cost centers making it difficult to determine with reasonable accuracy the
5 allocation of fleet responsibility costs to specific line items in various parts of the business.

6 **FLEET REPLACEMENT PLANNING PROCESS**

7 **Q. What is the Company's overall Fleet Replacement Planning Process as it is being**
8 **presented in this case?**

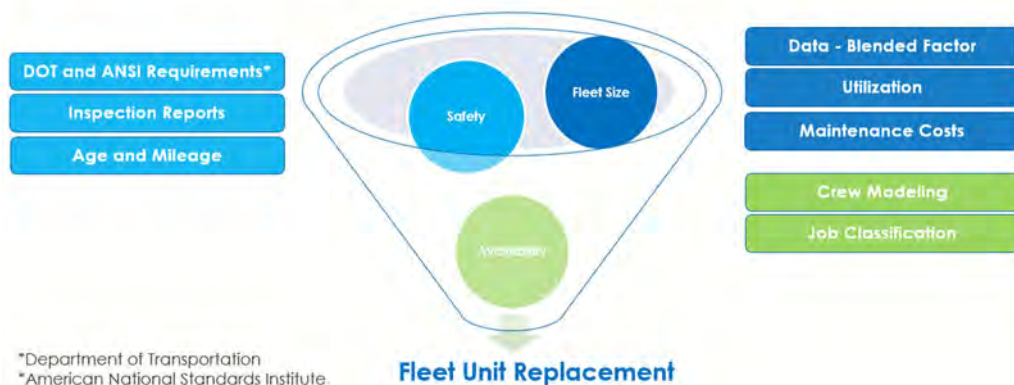
9 A. As previously presented in Electric Rate Case Nos. U-20963, U-21224, U-21389, and
10 U-21585, and Gas Rate Case Nos. U-21148, U-21308, U-21490, and U-21806, the
11 Company develops its Fleet Vehicle Capital Replacement Plan using the Fleet
12 Replacement Planning Process, which is a process that incorporates three phases. In the
13 first phase, the Company identifies vehicles that are at or near the end of their expected life
14 and are eligible for replacement, using a tool called the Blended Factor that is described in
15 more detail below. Next, in the second phase, the list of vehicles identified by Blended
16 Factor Analysis for potential replacement is further developed by certain data tools,
17 described below, particularly by fleet cost data, followed by crewing data, and, lastly, fleet
18 utilization data. In this second phase, the Company's fleet leadership also works with
19 Operations leadership and personnel in the field, which includes operators and mechanics,
20 to identify which specific units should be replaced, incorporating qualitative inputs like
21 maintenance reports and local area work needs. This second phase allows for further
22 evaluation of the vehicles identified in the first phase to better determine which vehicles
23 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 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 to vendors. 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.

Fleet Capital Replacement Plan Filter



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1 **Q. Please explain how the Fleet Capital Replacement Plan Filter works.**

2 A. When the Company goes through its Fleet Replacement Planning Process, specifically
3 within phases 1 and 2, certain data – such as the Blended Factor, utilization, operating cost,
4 and crewing needs – is analyzed to determine if a given vehicle needs to be replaced.
5 During the Fleet Replacement Planning Process, other qualitative inputs like vehicle
6 inspection reports and the assessments by field employees provide further insight on
7 replacement needs. The result of this process, specifically following the first and second
8 phase, is a list of fleet units to be replaced.

9 **Q. Can you describe, in further detail, the Blended Factor used in phase 1 and the Fleet**
10 **Cost Tool, Crewing Model Tool, and Fleet Utilization Tool used in phase 2?**

11 A. Yes. These are each described in the following sections.

12 **A. Blended Factor**

13 **Q. Please further explain the Blended Factor.**

14 A. The first step in the Company's process for establishing its Fleet Vehicle Capital
15 Replacement Plan is informed by the Blended Factor. As previously mentioned, the
16 Blended Factor takes age, usage, and mileage into consideration and establishes a
17 replacement priority for units that are more economical to replace than continuing to
18 maintain. The Blended Factor for any vehicle is calculated as shown in the illustrative
19 example below:

Blended Factor Calculation

$$\text{Blended Factor Rating} = \left(\frac{[\text{Age Factor} + \text{Usage Factor}]}{2} \right)$$

$$\text{Age Factor} = \left(\frac{\text{Actual Age in Months}}{\text{Expected Life in Months}} \right) - 1$$

$$\text{Example: } \left(\frac{102}{84} \right) - 1 = .21$$

$$\text{Usage Factor} = \left(\frac{\text{Estimated Mileage}}{\text{Expected Life Mileage}} \right) - 1$$

$$\text{Example: } \left(\frac{225,180}{150,000} \right) - 1 = .488$$

$$\text{Blended Factor Example: } \left(\frac{[.21 + .488]}{2} \right) = .349$$

Equipment and engine operation hour
calculation: 1 hour = 25 miles

For equipment that does not have mileage (no odometer), the Blended Factor calculates usage from the engine hours. For medium and heavy-duty vehicles, the Blended Factor calculation also uses total engine hours, assuming that one hour of engine operation is equivalent to 25 miles of travel. Using this calculation, a Blended Factor result greater than 0.00% indicates that a vehicle is at or past its expected life and is therefore eligible for consideration for replacement. This indicator does not mean that a vehicle with a result greater than 0.00% is automatically selected for replacement; it is instead a *starting point* each year for the Company to use as a foundation in the selection of vehicles for replacement.

Q. Why is it important for the Company to consider the expected life in months and expected life in mileage for each of the respective specs?

A. The Blended Factor formula incorporates two key indicators of 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,

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1 reliability, operating conditions, and operating cost to determine the duration the Company
2 expects a vehicle to operate safely and cost effectively. Expected life in mileage or hours
3 is also based on similar considerations as an indicator of wear and tear. The Company
4 makes these evaluations to set a foundational benchmark to assess potentially replaceable
5 vehicles. The fleet has a diverse range of specs for specific operational needs, and not all
6 specs have the same expected life. Even within the same spec, individual units can vary in
7 condition depending on utilization and wear. Managing each spec to its appropriate
8 expected life ensures that the Company always has the right type of vehicle available to
9 serve the needs of customers in the safest, most reliable, and most efficient manner
10 possible, while minimizing costs.

11 **Q. Why is the use of the Blended Factor appropriate?**

12 A. The Blended Factor is an internal data-based algorithm that incorporates unit age,
13 utilization (in mileage or hours), and expected life, allowing the Company to prioritize,
14 plan, and target specific vehicle(s) for replacement. As a key feature of the *first phase* of
15 the replacement process, the vehicles denoted by the Blended Factor to be approaching the
16 end of their expected life provide the basis for planning phases ahead. This process is
17 critical to ensure that the Company can order a timely unit replacement, especially given
18 the supply chain challenges that have emerged in the last three years. While there has been
19 some improvement in the expected delivery dates for some products, planning around
20 potential delivery delays and availability is still a concern as demand for new medium and
21 heavy-duty equipment remains high. By using the Blended Factor, the Company can
22 strategize future spending for replacement units for specific years by consulting with

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suppliers on current and future availability, thereby preparing the Company to order units given current lead times to receive a unit once an order is placed.

Q. What conclusions do you draw regarding the Blended Factor?

A. The Blended Factor provides an objective standard that uses clear internal fleet data to identify units for potential replacement and adds a level of predictability regarding which units will need to be replaced to improve the cost-effectiveness of the replacement process. Based on the above Blended Factor calculations, it is indicated that out of 7,207 units currently in the fleet, there are approximately 1,903 units greater than 0.00%.

B. Fleet Cost Tool

Q. Please explain the Company's fleet cost tool.

A. As part of the second phase in its Fleet Replacement Planning Process, the Company is utilizing the fleet cost tool, incorporating data analytical tools to support near- and long-term cost-effective vehicle purchase plans. These analytical tools include tracking vehicles by spec and the average age of each spec, fleet O&M costs, and geographical location. Additionally, the fleet cost tool provides at-a-glance total and average per-vehicle operating costs for each spec from various perspectives, including operating costs per mile, by age, and by specific vehicle. These tools provide data indicating vehicle count and average age, broken out by spec. The purpose of these tools is to provide overall cost status summaries of the fleet, as well as a platform to perform more detailed cost analyses of individual vehicles. The following are descriptions of several tools the Company has developed.

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1 **Q. What are these tools that the Company has developed to support fleet cost analyses?**

2 A. For an overall summarization of fleet age and operating costs, the Company has developed
3 “Unit Age and Operating Cost” and “Unit Count and Average Age” tools to provide
4 information regarding fleet operating costs correlated with age. Operating costs include
5 maintenance, fuel, and repairs. This information can be filtered by vehicle year and spec
6 and can assist in identifying trends that will enable cost forecasting to support future
7 purchasing decisions.

8 **Q. What are additional analytical tools related to fleet cost?**

9 A. The Spec Detail Information Analysis identifies equipment count by spec and is designed
10 to highlight yearly fleet composition by spec, which helps identify trends and how the
11 fleet’s makeup and size changes over time.

12 **Q. Are there any other analytical tools that are part of the fleet cost tool?**

13 A. The Age and Cost Spec Detail Analysis is designed to provide detailed cost information
14 for a specific unit, including total operating cost, as well as average costs over time for
15 specific specs. In this analysis, the Company evaluates equipment count, total operating
16 cost, average unit operating cost, median unit operating cost, and average unit age. Finally,
17 a Location Summary Analysis displays a particular territory, city, spec, equipment count,
18 and total operating cost for vehicles distributed throughout the Company’s service area.
19 Equipment Count by location is displayed on a map with circle size indicating high/low
20 equipment counts and color indicating zone. Average Unit Age and Total Operating Costs
21 are summarized in cards at the top of the page. This page allows the user to filter by Year,
22 Usage Indicator, Rental Status, and Specification. The purpose of this tool is to allow the
23 user to use the filters to summarize equipment count, cost, and age by location.

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1 **Q. Why are these fleet cost analytical tools appropriate for the Company to use?**

2 A. Using the Company's own data, the information these tools provide is used to help the
3 Company plan the cost-efficient replacement and acquisition of new vehicles. The Fleet
4 Cost Tool data provides information from several perspectives that helps narrow the pool
5 of vehicles identified by the Blended Factor for replacement. For example, the Blended
6 Factor may identify many units within any given spec that are at or near the end of their
7 expected life, but a further examination using this tool can help inform how the unit is
8 performing in relation to other identical spec vehicles in the fleet from a cost perspective.
9 If the unit has become uneconomical to operate compared to other vehicles in the same
10 spec, it may be best to replace that vehicle for a more cost-effective solution sooner rather
11 than later. Conversely, a vehicle that has reached the Blended Factor end of expected life
12 may still have years of economical service possible based on operating cost reported by
13 these tools. This fleet cost tool also allows the Company's fleet management to understand
14 how fleet costs have changed year-over-year, including the ability to examine costs of
15 specific units to help inform if they are good candidates for replacement. The tool is
16 intended to provide an overview of past fleet metrics, and helps to identify relationships
17 between unit age, mileage, and operating costs. It also shows fleet age by spec which can
18 be helpful when multiple units of the same spec were purchased in the same year. This is
19 valuable information to consider when prioritizing the most appropriate vehicles to replace
20 at any given point for the benefit of customers.

21 **Q. What has the Company learned to date from using its fleet cost tool?**

22 A. The fleet cost tool has allowed the Company to make informed decisions while reviewing
23 units identified for replacement. This tool provides the Company with an at-a-glance total

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1 of overall costs of a particular unit. As the fleet team strategizes how and where to replace
2 vehicles, the cost tool assists in framing how to best benefit the customer in the
3 decision-making process.

4 As noted, the Blended Factor calculation is a starting point in the decision-making
5 process, with the expectation that the list can be modified as further analysis proceeds. The
6 cost tool facilitates a review of repairs and improvement costs associated with each vehicle
7 that can extend its service life. For example, feedback sought and received from field
8 leaders on the overall condition and serviceability of a truck can show that it should be kept
9 in service instead of being replaced. This includes investments like engine or transmission
10 rebuilds, or body rust repairs. The fleet cost tool quickly identifies which units require
11 closer scrutiny when making purchasing decisions. This benefits the customer in that the
12 Company gets as much service life out of units as is economically prudent.

13 **C. Crewing Model Tool**

14 **Q. Please explain the Company's crewing model and crewing model tool.**

15 A. As part of the second phase of its Fleet Replacement Planning Process, the Company's
16 crewing model is used to calculate how many vehicles are needed based on the size of the
17 workforce. This model incorporates all electric department vehicles and details about
18 which employees are assigned to operate these vehicles. The electric departments include
19 Customer Field Services, Electric Meter Operations, Low Voltage Distribution ("LVD"),
20 and Substation Maintenance. These departments operate the following types of vehicles:
21 bucket trucks, digger derricks, service buckets, pickup trucks, and other support vehicles.
22 The crewing model tool illustrates how many vehicles are needed and how many vehicles
23 are available, giving visibility to gaps.

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Q. What information does the tool show?

A. The tool lists Company locations and, for each location, shows the number of units at that location by workgroup, breaking down the number of employees and the number of different types of units located there. Based on this information, the tool provides the gap between the actual number of vehicles at the location and the number of vehicles needed.

Q. How was this crewing model developed?

A. The Company's Electric 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:

- Electric LVD crewing consists of one Line Worker in Charge ("LWIC"), one Journeyman Line Worker ("JLW"), and one Apprentice to make one crew. Each crew is assigned a bucket truck and a support vehicle. The support vehicle could be a digger derrick or a pickup. The current crewing model calculates vehicle needs according to the following ratios:

Vehicle Type	Model Ratio
Bucket Truck	1:1 LWIC to Bucket Truck
Digger Derrick	2:1 LWIC to Digger Derrick
Pickup	2:1 LWIC to Crew Vehicle
Trencher	4:1 LWIC to Trencher

- Employees in Electric Meter Operations, Customer Field Services, Electric Field Lab, and Substation Maintenance 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

¹ 1926.960 - Working on or near exposed energized parts. | Occupational Safety and Health Administration (osha.gov): <https://www.osha.gov/laws-regs/regulations/standardnumber/1926/1926.960>

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1 fleet, it is important that the Company's fleet be adequate in size to complete the established
2 work plan, work safely, and adhere to OSHA requirements.

3 **Q. What conclusions can you draw from the data shown in the crewing model tool?**

4 A. The model shows that the quantity of production units (bucket trucks, digger derricks, and
5 service bucket trucks) currently in the Company's fleet will continue to be evaluated based
6 on established work plans and employees needed to perform the work (more information
7 on how utilization data is calculated is provided in the next section of this testimony). The
8 model can help identify surplus or deficiency of assets in each specific area and units that
9 are down for repairs or regular maintenance. This visibility allows the Company to
10 reallocate surplus assets to areas with deficiencies to ensure each area is adequately
11 supplied based on the model. Backup vehicles must be ready to meet the needs of the
12 crews as daily schedules develop, meaning that some additional vehicles may be needed
13 on short notice. The Crewing Model allows for backup vehicle availability for such
14 circumstances to reduce the risk of gaps between crews and vehicles needed in the field.

15 The crewing model assumes the Company will onboard new workers or add
16 replacement workers consistently and in a timely manner as work plans develop to drive
17 the need for workers and as attrition rates affect the workforce. However, the Company
18 does not always receive new vehicles at the same time new workers are onboarded. For
19 this reason, it is possible that new vehicles will be received and paid for before workers are
20 ready to use them, but those vehicles *will* be put into use once the planned hiring is
21 complete. Utilization rates for vehicles may at times reflect this reality.

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1 **Q. What has the Company learned to date from using its Crewing Model?**

2 A. The Crewing Model offers the ability to find gaps in available units, and much like a
3 checklist, allows the Company to proactively prepare for any emerging vehicle needs based
4 on how new projects and employees are planned or deployed. In this manner, the Crewing
5 Model complements the other fleet tools the Company is developing by ensuring that units
6 are allocated as effectively as possible before and after any new units are purchased. The
7 customer benefits from this because the Company is constantly working to keep its fleet
8 right sized, with as few redundancies as possible.

9 **D. Fleet Utilization Tool**

10 **Q. Please explain how the Company captures utilization data for its fleet.**

11 A. All vehicles use a Telematics device that is directly wired to that asset's onboard computer
12 or switching. Each installed Telematic device communicates, via cellular signal in real
13 time, information about the asset status including the unit's exact Global Positioning
14 System ("GPS") location, date, time, mileage driven, and hours in operation. A vehicle is
15 considered in use for any given day when it has traveled five or more (5+) miles at any
16 time or equipment that is in operation for thirty or more (30+) minutes per day. This
17 captured data is then uploaded and compiled on a nightly basis into one tool that can then
18 be used to run reports as needed to manage the operation. This data is compiled into a fleet
19 utilization tool that can provide fleet use by zone, by vehicle type, or department and is
20 used as part of the second phase in the Fleet Replacement Planning Process.

21 **Q. How was this data process developed?**

22 A. The electronic information captured by the Telematics system documents industry standard
23 data points that are used to log key vehicle information. Since 1996, every vehicle

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1 manufactured in the United States has an On-Board Diagnostic (“OBD”) port/interface that
2 can easily be made accessible to Telematics systems and their associated electronic data
3 gathering capabilities. The OBD system provides access to a vehicle’s Electronic Control
4 Unit, the main computer that controls vehicle engine, transmission, and other key vehicle
5 functions. By connecting directly to the OBD of each vehicle, the Telematics system is
6 able to collect the real-time information required to inform the Company to log the key
7 data points required to document utilization.

8 **Q. How is the Company’s utilization data tied to the crewing model?**

9 A. As explained in the crewing model section, vehicles are assigned in response to the
10 requirements of the daily work plan and the employees needed to complete the work. Some
11 types of vehicles, like bucket trucks, are used frequently for common field operations,
12 whereas there are other types of vehicles that are highly specialized and designed for
13 specific tasks that are not always required on a given day/night to serve customers but are
14 no less crucial to properly service customers throughout the state. The Company’s
15 utilization data also accounts for the downtime that equipment must undergo when
16 receiving inspections, maintenance and repair, or other ancillary equipment upgrades, and
17 for the fact that some equipment must be available for on-call assignments and off-hour
18 assignments.

19 **Q. Why is this approach to utilization data appropriate for the Company to use?**

20 A. By capturing real-time telematic data from each asset and compiling it in one dataset, the
21 Company obtains the required raw data to detail the exact frequency, duration, and overall
22 use of each asset, and this data is then searchable for reporting utilization rate purposes.
23 Utilization data can illustrate where units may be underutilized. The customer benefits

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1 from this approach because the Company ensures that all vehicles and assets are tracked,
2 monitored for maintenance and safety, and allows for the optimal cost-benefit relationship
3 and return on investment for its fleet. This approach supports the analysis of what assets
4 the Company needs to purchase to be sure that it is replacing vehicles at the end of their
5 lifecycles, and to be sure that the Company is serving customers with safe, capable, and
6 effective equipment.

7 **Q. What conclusions do you draw from the Company's fleet utilization data?**

8 A. The Company's utilization rate data informs us that a continual review of fleet equipment
9 for under-utilized vehicles, what areas of the business they serve, and how that may impact
10 the Company's ability to serve its customers, will be on an ongoing analysis. It is a key
11 tool in determining why and where vehicles may be down (or showing lower utilization
12 rates). For example, vehicles that are down for repair or waiting for parts are different from
13 vehicles that are available but are not being used to serve customers when evaluating
14 utilization rates. The Company analyzes its fleet utilization to determine if there are any
15 redundancies that can be dispositioned in the future, such as through attrition and
16 reallocating to raise utilization to more optimal levels.

17 **E. Benefits**

18 **Q. Please summarize the Company's Fleet Replacement Planning Process.**

19 A. The Company's fleet consists of 7,207 units of varying specs utilized for specific tasks to
20 serve customers, divided between the electric and gas sides of the business. Assets referred
21 to as "common units" are utilized by various other departments within the Company to
22 support business operations. The Company employs a Fleet Replacement Planning Process
23 (Replacement Filter, Blended Factor, Cost Data, Utilization Data and Crewing Models) to

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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 of significant investments such as a new engine or transmission in a vehicle that could extend its service life. The customer benefits from this analysis because the Company is using fleet dollars in the most economical way possible.

Q. What are the benefits of the Crewing Model for customers?

A. Having the ability to tie the workforce to the right vehicle by location enables the Company to have visibility to align assets with the workplan by department and location. As the Company strives to be a good steward of the fleet, the model helps validate if additional

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units are needed to meet the Company's workplan or, alternatively, if the Company has any surplus units that can be redeployed or retired. Absent this, the Company may end up lacking the appropriate vehicles to complete work for the customers' benefit.

Q. What benefits does fleet utilization data provide for customers?

A. Peak utilization of all vehicles is a balance between fully utilizing purchased assets and having the right asset in place and ready when needed at a moment's notice when responding to outages, new business, or construction situations. Fleet assets other than specialized equipment that are underutilized are not providing the maximum benefit to the customer. As good stewards of its fleet, the Company must provide the most cost-effective methods to ensure 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 in which said vehicle is designed to operate. 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

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1 will inform decisions on how many future investments in that type of vehicle are made
2 going forward. Customers benefit when the Company is making best use of its fleet to
3 deliver service. Utilization data helps the Company right-size its fleet by identifying where
4 additional units are needed to accommodate the Company's workforce, if there are any
5 surplus units, and if existing units can be more effectively used by the Company, such as
6 by moving units to a new location or new department.

7 **Q. Have there been right sizing efforts that benefit the customer?**

8 A. Yes. Since mid-2022, the Company has reduced its total number of units by approximately
9 450 units utilizing the tools described above. These right sizing efforts benefit the customer
10 by reducing overall cost through reductions and/or allowing a particular unit to be
11 effectively utilized in support of serving customers.

12 **Q. How does the Company's overall Fleet Vehicle Capital Replacement Plan benefit**
13 **customers?**

14 A. Overall, the Fleet Vehicle Capital Replacement Plan allows the Company to retire and
15 replace vehicles in a cost-effective way by using qualitative and quantitative inputs to
16 identify units for replacement, particularly by identifying those units with high
17 maintenance costs and exhausted expected useful lifespans. Retiring and replacing those
18 units in a systematic way is designed to keep maintenance costs down while ensuring that
19 vehicles are available when needed to serve customers. The replacement planning process
20 is a constantly self-evaluating cycle that relies on the data the fleet itself generates over
21 time (mileage, age, and life cycle expectancy), inspections, maintenance and repair costs,
22 and the local expertise to assist in prioritizing how the Company replaces units in the fleet.
23 The customer benefits from this replacement planning process because the fleet is a crucial

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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-

- o 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.
- o 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.
- o 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-

- o 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.
- o 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 occurred about every two years.

Planet–

- o 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.
- o Fossil fuel powered vehicles may be replaced with an EV if data supports electrification in that instance and could be a more fuel-efficient mode of transportation.

FLEET ELECTRIFICATION STRATEGY

Q. Does the Company plan to increase the number of EVs in its internal fleet?

A. Yes, the Company is planning to increase the number of EVs in its fleet to reduce fleet fuel, maintenance, and operating costs, as well as lowering carbon dioxide tailpipe emissions to reduce greenhouse gases. For purposes of this testimony, the Edison Electric Institute’s definition of an EV includes all vehicles with a plug, including Battery EV, Plug-in Hybrids, and anti-idle job site work systems such as electric Power Take Off systems (“ePTO”) units.

Q. How many EVs does the Company have in its internal fleet currently?

A. The Company’s fleet currently operates 302 EVs, representing approximately 5% of powered units in the overall fleet.

Q. Does the Company have a target goal for electrification of its internal fleet?

A. Yes, as noted by the Michigan Council for Future Mobility and Electrification in its 2021 report, the decade ending in 2030 will be notable in that the growth of EVs in the state will present new opportunities for the Company and its customers.² This is consistent with the

² cfme_report_2021_02.pdf (michigan.gov):
https://www.michigan.gov/leo/-/media/Project/Websites/leo/Folder28/cfme_report_2021_02.pdf

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testimony of Company witness Jeffrey A. Myrom in the Company's most recent electric rate case, Case No. U-21585. Leading by example, the Company has, therefore, set a goal of electrifying 30% of its internal fleet by the year 2030, including light, medium, and heavy-duty vehicles (class 1 through class 6 and higher), equipment and powered trailers, as well as electrifying all class 1 and 2 (light duty) vehicles after 2030.

Q. How many vehicles does the Company plan to convert to electricity as a source of fuel by 2030?

A. The internal fleet currently consists of approximately 5,700 powered vehicles eligible for replacement by potential EVs. This includes sedans, pickup trucks, bucket trucks, forklifts, and others. Electrifying 30% of these units would result in the replacement of approximately 1,700 internal combustion engine ("ICE") units with fully or partially EV powered units by 2030.

Q. What types of vehicles does the Company expect to replace with EVs?

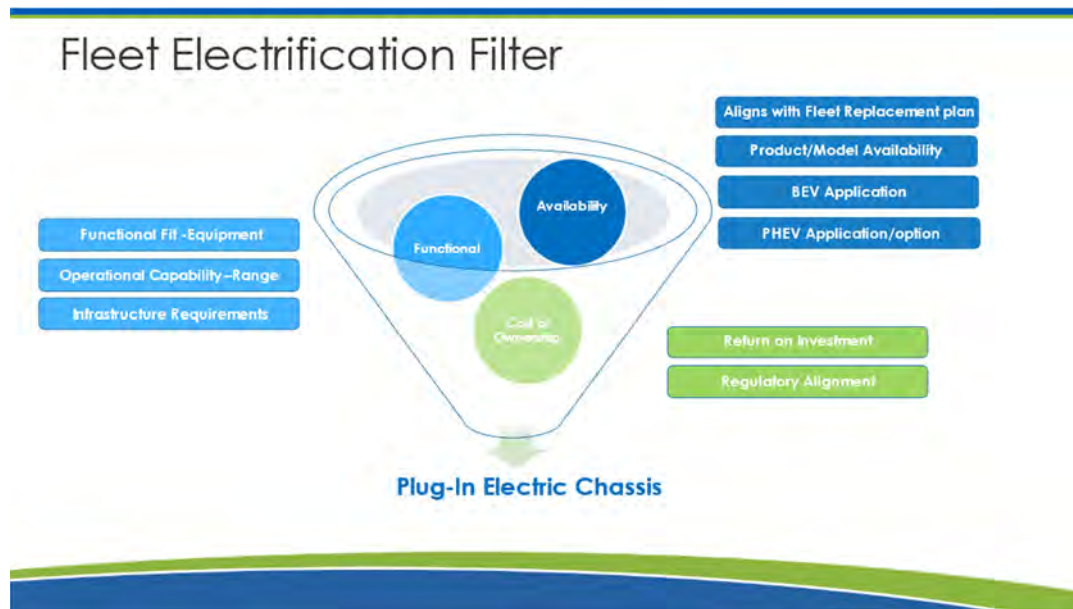
A. The Company expects that most of the initial ICE vehicles it will replace will be sedans and pickup trucks; however, as battery technology develops, there will be increasing availability for medium and heavy-duty vehicles to enter the market. For example, the Company has purchased one of the first available all electric bucket trucks in the world, which was delivered in the third quarter of 2024, as well as 20 all-electric pickup trucks. The Company will deploy the electric bucket truck in its Grand Rapids location and has installed a DC Fast Charger there to support it.

Q. How will the Company determine opportunities to replace ICE vehicles with EVs?

A. The same replacement process, as discussed earlier in my testimony, will be used to determine opportunities to replace ICE vehicles with EVs, including the use of the Blended

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Factor, unit age, and overall condition analysis for each unit that has reached its end of life. Under this process, as a unit is targeted for replacement and reviewed according to the Replacement Plan, the unit is also considered for replacement with an EV. As the Electrification Filter shown below shows, consideration for electrification includes assessing a suitable replacement that is available in market, would have a functional role within the fleet, and lower cost of ownership. If the ICE under consideration for replacement meets the criteria required to pass through the filter, the unit is considered as an opportunity for replacement with an EV.



Q. Why is the Company concerned by functional fit and equipment considerations?

A. The Company partners with operational departments to understand how the potential replacement of an ICE vehicle with an EV will impact how teams complete their work. It is important to understand vehicle travel patterns, including mileage and driving duration, to assure that EVs are capable of supporting the work and have the travel range the Company needs to serve customers without compromise.

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1 **Q. Why is the Company considering range concerns with EVs?**

2 A. As noted above, mileage range is a top consideration in determining how the Company
3 integrates EVs into the fleet. It is critical to understand how current vehicles operate to
4 determine potential EV replacement options, as well as infrastructure preparedness. The
5 Company is utilizing its trip data, including mileage and location, to understand the best fit
6 for each EV it is considering.

7 **Q. Why is functional fit a critical part of the EV decision making process?**

8 A. As with all other vehicles, the Company strives to ensure its Fleet aligns with industry best
9 practices to serve the customer safely and efficiently. It will be important to consider, in
10 addition to range, how an EV will support each department's ability to use it to its fullest
11 capabilities, such as carrying tools and employees as required by the work.

12 **Q. How will the Company determine if EVs are performing as expected?**

13 A. The Company will be expanding its internal focus groups to provide real world feedback
14 on barriers and opportunities to continuously improve how the Company adapts EVs in
15 various operational environments. The Company will also study how EVs perform from a
16 cost perspective, with lower maintenance and fuel costs expected.

17 **Q. In what ways are EVs more beneficial than ICE vehicles?**

18 A. Most of the benefits gained from utilizing EVs or battery-assisted systems arises from the
19 changeover to electricity as the main source of energy, instead of gasoline or diesel fuels
20 and petroleum-based maintenance materials. Electric motors require much less powertrain
21 maintenance and repair, resulting in reduced maintenance costs, which is one of the key
22 benefits of electrifying fleet units. A fully EV (battery) powered vehicle can also have up
23 to 80% fewer parts than its ICE counterpart. With fewer internal parts, electric motors

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1 operate with less friction and more efficient use of energy. Many ICE vehicle parts require
2 frequent and costly maintenance routines. Further, up to 65% of the heat energy produced
3 by an ICE is wasted, requiring cooling systems which are prone to wear and eventual
4 failure.

5 **Q. Can you please give examples of reductions in maintenance that will arise out of a**
6 **transition from ICE vehicles to EVs?**

7 A. ICE vehicles contain hundreds of oil-lubricated parts that are required to convert the
8 combustion of fossil fuels into mechanical energy. Fluid changes extend to other
9 components needed at various intervals in addition to engines and transmissions, including
10 transfer cases and differentials throughout the life of all ICE vehicles. All these systems
11 require regular maintenance and the associated costs in labor, parts, and materials to keep
12 them at optimum performance and longevity. Over time, however, these components
13 continue to wear even with diligent maintenance. This wear often leads to overheating
14 issues, damaged or broken hoses, worn coolant pumps, or engine failure with the associated
15 down time while undergoing repairs. EVs, on the other hand, do not require oil changes,
16 spark plugs, fan belts, or tune ups. EVs also do not have transmission fluids that require
17 periodic fluid changes, which makes them less prone to failure. Further, since an EV drive
18 train requires less attention from a maintenance perspective, there is a reduced need for
19 labor and/or material costs associated with this aspect of maintaining an EV. Plug-in EV
20 hybrids often work with an ICE in conjunction with electric motors, reducing the fuel
21 requirements for units equipped this way. Depending on the vehicle's configuration, a
22 hybrid that features an ICE may need a maintenance schedule like a regular ICE vehicle;

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1 however, in most cases, plug-in hybrids help reduce overall fuel consumption with
2 extended periodic maintenance requirements.

3 **Q. Are there other tools available to reduce fossil fuel consumption in ICE vehicles?**

4 A. Yes, there are idle-mitigation technologies, using plug-in battery systems, designed to
5 reduce fuel consumption by reducing idle hours required to operate ancillary equipment
6 such as a boom on a bucket truck. By employing a plug-in battery and electric motor, for
7 example, ePTO units can power hydraulic systems for short periods, reducing fuel
8 consumption and engine wear. When engaged at a jobsite, an ePTO system can shut an
9 idling engine off, and a battery-powered motor then powers the hydraulics needed to
10 position the boom and bucket, as well as powering the climate control system in the cab.
11 As a result, the bucket truck will operate quietly while the operator performs work near a
12 customer's home because the sound of an idling diesel will not be present while the ePTO
13 system is engaged. The Company already employs this technology to help reduce idling
14 hours on several specs that operate booms on bucket trucks and cabin climate control.
15 Additionally, ePTO systems can reduce fleet's overall carbon dioxide tailpipe emissions,
16 as well as diesel particulates.

17 **Q. Has the Company undergone a concierge cost benefit analysis to help plan for internal**
18 **EVs?**

19 A. Per Case No. U-20963, the Company has partnered with CALSTART, a national non-profit
20 with over 30 years' experience in the private and public sectors with a proven track record
21 working with over 280 member companies and agencies to build business cases for clean
22 transportation technology adoption. CALSTART is a nationally respected team of fleet
23 electrification experts who were selected by the Company via a competitive Request For

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1 Proposal. CALSTART has completed numerous fleet electrification assessments for
2 external customers, in addition to the Company's assessment. The Company's fleet
3 assessments were conducted between August 2022 and October 2023 and analyzed the
4 Company's light, medium, and heavy-duty fleet vehicles, by location, and daily miles
5 driven to provide approximate load demand by location. EV location determination helps
6 in understanding potential carbon emission avoidance and cost benefit analysis.

7 **Q. Does the Company solely rely on the CALSTART assessments for determining what**
8 **EV to purchase?**

9 A. The Company does not rely solely on the CALSTART assessment in its planning for EVs.
10 CALSTART used the Company's own fleet-generated data to compile a list of
11 recommendations for vehicle locations that are potentially suitable for electrification, the
12 estimated load demand for those locations, and the associated charging information to
13 support them. This information assists the Company during the decision-making process
14 when considering EVs.

15 **Q. What quantifiable benefits of electrifying vehicles did CALSTART's assessment**
16 **determine?**

17 A. CALSTART's assessment, noted above, concluded that the Company has the potential to
18 lower fleet's overall fuel and maintenance costs by approximately 70%, excluding vehicle
19 purchase price, combined over the lifetime of the vehicles that are electrified. The
20 assessment also concluded that the Company could potentially reduce tailpipe emissions
21 by approximately 90,000 metric tons.

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1 **Q. Did the assessments provide suggestions for EV infrastructure support?**

2 A. The assessments provide specific location-based electric load demand estimates for the
3 light duty EVs planned for replacement, as well as electricity as fuel cost estimates based
4 on current mileage driven by ICE vehicles. For each service center/office location, the
5 Company's ICE light-duty fleet data was analyzed for average daily miles driven and
6 applied this information to determine the appropriate level of charger (Level 1 or Level 2)
7 and the estimated corresponding energy demand for each vehicle. With this information,
8 the Company can plan for the specific infrastructure electrical upgrades needed to support
9 the installation of Electric Vehicle Supply Equipment ("EVSE") at respective service
10 centers with a measure of predictability based on the information the Company's ICE fleet
11 has generated.

12 **Q Is there a cost difference between EVs and conventional fossil fuel vehicles?**

13 A. Depending on make, model, and mileage range ratings, the purchase cost for an EV can
14 vary as compared to an ICE vehicle. Currently, there are usually higher purchase costs
15 associated with EVs that are comparable to ICE vehicles used by the Company to service
16 its customers, such as all electric pick-up trucks.

17 **Q. Can you provide an example of a suitable EV for the Company?**

18 A. When considering an EV replacement, the Company seeks the closest EV equivalent to the
19 out of lifecycle ICE under consideration for replacement. Currently, vehicles are more
20 closely aligning with pickup trucks and economical sedans as most suitable for
21 transportation and operational support. The Company is also interested in the business and
22 operational stability of the manufacturer to assure continued support over of the lifetime of
23 the vehicle.

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1 **Q. Are there other associated projects being planned to support vehicle electrification**
2 **efforts?**

3 A. Yes. To support the growth of EVs, the Company must plan for the increased electric load
4 demands at most of its service centers to charge the EV units at those service centers. Since
5 each center location will have a varying number of EVs and load demands, each location
6 will require a specific power demand-based upgrade of its electric infrastructure for the
7 installation of EVSE, also commonly known as “chargers.” As noted earlier in my
8 testimony, fleet has undergone a detailed data-based assessment by CALSTART to
9 forecast the load demands each facility may need to charge EVs daily.

10 **Q. How many potential EV opportunities are identified in the Five-Year Purchase Plan?**

11 A. Based on the currently available EV vehicles offered by manufacturers, the Five-Year
12 Purchase Plan currently identifies approximately 120 to 130 potential opportunities for a
13 suitable 1:1 replacement of an ICE with an EV based on replacing units that have reached
14 their end of life. Most of these vehicles are light duty pick-up trucks, and plug-in battery
15 idle mitigation units on bucket trucks. There are about 22 light duty vehicles that could be
16 replaced with an EV in 2026, and 20 opportunities in 2027, 23 in 2028, 22 in 2029, and
17 approximately 25 to 30 units in 2030. With limited opportunities to make ICE to EV
18 replacements through 2027, the Company would need to invest additional funding above
19 the currently approved capital replacement funding for the purchase of approximately
20 450 EVs over and above what the Purchase Plan identifies as a replaceable unit each year
21 in 2028, 2029, and 2030 to reach the Company’s goal of approximately 1,700 EVs.

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1 **Q. Is the market for vehicle electrification currently able to supply the vehicles needed**
2 **to support the Company’s goal?**

3 A. Lead times for some EVs and vehicles equipped with idle mitigation systems are often two
4 or more years out. The resources required by manufacturers to build enough units to meet
5 high demand are not aligned, which has often led to short supplies for both commercial
6 and private customers; however, the market’s availability of EVs suitable as fleet vehicles
7 is still a relatively small part of the EV market. Currently, a substantial portion of the EV
8 market consists of vehicles that do not meet the criteria for cost and features best suited for
9 use by the Company. For example, the Company prefers Original Equipment Manufacturer
10 (“OEM”) vehicles from Michigan-based companies, such as General Motors and Ford, as
11 well as meeting all the requirements noted as part of the Fleet Electrification Filter. The
12 recent fall in EV demand for EV pick-up trucks has shifted manufacturer focus to other
13 models or delayed the development of new EVs. There are many startup companies with
14 potentially viable EV units; however, the Company prefers to limit the potential exposure
15 to the risks associated with startup company products.

16 **Q. How does limited availability of EVs affect the Company’s goal?**

17 A. The Company’s ability to increase the number of EV units in the fleet remains flat through
18 2027. At this time, limited market EV availability may prevent the Company from ordering
19 a suitable number of EV units needed to affect a more linear glidepath toward the 2030
20 goal. Also, the EV opportunities identified in the Purchase Plan averages about 20 to
21 25 units per year. If the Company continues to purchase EV units at this pace per year, the
22 goal to electrify 30% of the fleet will not be met by 2030.

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1 **Q. What EV units does the Company plan to purchase for the Test Year?**

2 A. The Company is planning to replace 10 ICE pick-up trucks with 10 plug-in electric EV
3 pick-up trucks.

4 **Q. How will the Company determine the locations to assign EV vehicles?**

5 A. All EVs will be assigned to departments and teams that are best able to utilize the benefits
6 of an EV during their daily job functions. As discussed earlier in my testimony, the
7 assessment from CALSTART provides a summary of miles driven by location, allowing
8 the Company to understand where an EV can be best utilized. For example, where the data
9 shows an ICE pickup truck is typically driven 75 to 150 miles per day and returns to its
10 respective service center, that vehicle could be eligible to be replaced with an EV of similar
11 capability and range because the data suggests a good fit for an EV. The Company can
12 reference the assessment data to help make the most informed decisions on their
13 deployment. The Company also partners with operations to determine if an EV will meet
14 the requirements of their work processes at a particular location.

15 **Q. What associated infrastructure support will the EVs planned for the Test Year**
16 **require?**

17 A. The EV units will require chargers installed at their planned respective headquarters to
18 support their charging requirements. The planned headquarter locations that will need EV
19 chargers installed are as follows: Jackson, Royal Oak, Lansing, Bay City, Battle Creek,
20 and Adrian.

21 **Q. How does electrification of 30% of the Company's fleet by 2030 benefit the customer?**

22 A. The Company's efforts to electrify a portion of the internal fleet could benefit the customer
23 in several ways. The Company seeks to lower Fleet's overall operating costs by reducing

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1 its reliance on fossil fuels, which will bring lowered maintenance costs for reasons
2 mentioned earlier in this testimony. By shifting the cost of refueling an ICE unit from
3 gasoline or diesel to overnight charging, the Company can save money on fuel wherever
4 mileage powered by fossil fuels can be shifted to lower cost charging overnight rates. Over
5 the lifetime of these vehicles, by utilizing electricity to power 30% of the fleet, the
6 Company seeks to leverage the relative stability and lower cost electricity offers over the
7 more volatile cost of petroleum-based fuels and lubricants. Reducing the Company's
8 reliance on ICE vehicles brings significant reductions in the maintenance costs associated
9 with the upkeep of fossil fuel-based drivetrains. With fewer mechanical parts to maintain,
10 EVs require lower maintenance budgets and fewer parts that can potentially fail over the
11 lifetime of the vehicle.

12 Lastly, by lowering its reliance on fossil fuels, the Company seeks to lower its
13 overall carbon dioxide emissions from Fleet's operations. Fully electrified vehicles have
14 zero tailpipe emissions and, where applicable, hybrid vehicles and other technologies (like
15 idle mitigating ePTO systems) also offer carbon reductions as well. Where idle mitigation
16 systems are employed with diesel engines, reduced idling lowers particulates, or soot,
17 generated with the combustion of diesel fuel. The Company's customers will benefit from
18 the efforts to mitigate pollution, reduce greenhouse gas emissions, and lower its overall
19 operating costs related to operating its internal fleet.

FLEET SERVICES CAPITAL SPENDING PROJECTIONS

Q. Please describe the capital expenditures related to Fleet Services as shown on Exhibit A-12 (QAG-1), Schedule B-5.6.

A. Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, provides electric Fleet Services capital spending, broken down into five capital spending categories: (i) Fleet Vehicle Capital Replacement, (ii) Fleet Vehicle Electrification, (iii) Fleet Expansion, (iv) Fleet Business Partner Funded, and (v) Fleet Tools - Garage. Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, provides these capital expenditures with actuals for the 12 months ended December 31, 2024; projections for the 12 months ending December 31, 2025; 4 months ending April 30, 2026; 16 months ending April 30, 2026; and projections for the 12 months ending April 30, 2027, which is the test year in this case. For the historical year, 12 months ended December 31, 2024, the Company incurred Fleet Services capital expenditures in the amount of \$16.628 million. The Company is projecting electric Fleet Services capital expenditures to be \$21.581 million for the 12 months ending December 31, 2025; \$4.368 million for the 4 months ending April 30, 2026; \$25.948 million for the 16 months ending April 30, 2026; and \$67.947 million in the projected test year ending April 30, 2027, as set forth in Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, 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.

1 **Q. What types of expenditures are included in Fleet Vehicle Capital Replacement Plan**
2 **and Expansion high voltage distribution (“HVD”) capital spending?**

3 A. Details of the Fleet Vehicle Capital Replacement Plan are included at Exhibit A-104
4 (QAG-5).

5 **Q. What types of expenditures are included in Fleet Vehicle Capital Replacement Plan**
6 **and Fleet Vehicle Electrification capital spending?**

7 A. Fleet vehicle electrification expenditures include the offset cost of 10 EV pickup trucks,
8 two units for electric and eight units for common use, as well as 12 Altec JEMS ePTO
9 systems in spec 64 bucket trucks.

10 **Q. What types of expenditures are included in Fleet Business Partner Funded?**

11 A. Fleet Business Partner Funded expenditures include one pick-up truck supporting the
12 Company’s solar renewable generation sites.

13 **Q. What types of expenditures are included in Fleet Tools?**

14 A. Fleet tool purchases include the following: diagnostic equipment, tool sets, ergonomic
15 tooling, and specialty equipment to properly and safely service and repair fleet vehicles,
16 equipment, and trailers. This is described in detail later in my direct testimony.

17 **Q. How did you determine the appropriate distribution of capital costs among the cost**
18 **categories shown on Exhibit A-12 (QAG-1), Schedule B-5.6?**

19 A. As required by the Commission’s filing requirements, the Company itemized the capital
20 investments for Transportation Equipment by using the following cost categories:
21 contractor, labor, materials, business expenses, and other. The Company breaks out these
22 cost categories by calculating a five-year historical average of each of the Commission’s
23 prescribed cost categories from years 2020 thru 2024 as a percentage of total

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1 Transportation Equipment investment over that same period. The five-year historical
2 average for each cost category was then applied to the Transportation Equipment
3 Program's projected capital spending for the bridge year and the test year to arrive at
4 estimates for each cost category (i.e. contractor, labor, materials, business expenses, and
5 other). This method is consistent for the projected test year presented in Exhibit A-12
6 (QAG-1), Schedule B-5.6, pages 5 and 6.

7 **A. Fleet Vehicle Capital Replacement Plan**

8 **Q. What level of Fleet Vehicle Capital Replacement Plan spending is proposed in this**
9 **case?**

10 A. As shown in Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, the Company is proposing to
11 spend \$19.882 million in the 2025 bridge year; \$4.282 million for the 4 months ending
12 April 30, 2026; \$24.164 million for the 16 months ending April 30, 2026; and
13 \$20.778 million in the 12 months ending April 30, 2027 test year on Fleet Vehicle Capital
14 Replacement Plan spending.

15 **Q. How did the Company determine its 2024 through 2027 Fleet Vehicle Capital**
16 **Replacement Plan for the instant case, including the appropriate level of investment?**

17 A. The Company is keeping Fleet Vehicle Capital Replacement Plan spending in 2024
18 through 2027 at historical spending levels, adjusted for inflation, based on what the
19 Commission has previously approved for "lifecycle replacement spending." By remaining
20 at this level for 2024 through 2027, the Company is demonstrating its commitment to
21 keeping costs affordable for customers.

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1 **Q. How did the Company develop the list of vehicles that is projected to be purchased in**
2 **years 2024 through 2027 of this case?**

3 A. The specific units that the Company plans to purchase 2024 through 2027 are also shown
4 in Exhibit A-104 (QAG-5). The Company produced an initial list of vehicles for
5 replacement using the Blended Factor algorithm described earlier in my testimony, with a
6 spreadsheet showing a Blended Factor percentage for each vehicle in the Company's fleet.
7 This list was prioritized by the Blended Factor percentage to highlight vehicles that
8 generate a positive (above 0.0%) percentage (the mathematical result of the Blended Factor
9 calculation), which indicates that a vehicle has reached its expected life. Following the
10 Blended Factor Analysis, as described previously in this testimony, the Replacement Plan
11 filter included a review of market availability. By reviewing market availability, the
12 Company can determine which replacement specifications can be expected for delivery
13 through 2027. Vehicles that are likely not available for delivery in 2025 were not
14 considered for replacement. To further refine the list of vehicles, standard crewing models
15 were assessed. Though the Company will be continuing an analysis on right sizing,
16 standard modeling helped guide the decision-making process.

17 **Q. Was there additional analysis in determining the Fleet Vehicle Capital Replacement**
18 **Plan for 2025 and 2026?**

19 A. Yes. The list was further reviewed from a cost and utilization perspective. By assessing
20 how often vehicles are used, the Company selected vehicles with a higher utilization rate
21 when compared to similar specifications. The Company further narrowed the initial
22 Blended Factor-based list based on fleet stakeholders' input on condition. In this step,
23 vehicles were assessed by age, mileage, and overall condition, and associated operating

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costs and mechanical improvements, such as a newly installed engine. Vehicles that received recent substantial investments (new engines, for example) are removed from the potential replacement list because their expected life is generally extended following such investments.

Q. Does the Company anticipate variances in future fleet spending?

A. While the Company attempts to be as precise as possible in the Fleet Replacement Plan, there is the potential for variances slightly above or below projected budget due to the nature of the fleet business that includes supply chain challenges. However, the Company continues to be good stewards of the fleet by working to meet all projected expenditures as close to targeted goals as possible.

B. Fleet Vehicle Electrification

Q. In the projected test year, 12 months ending April 30, 2027, the Company is projecting an investment of \$840,000 for EVs. What is included in this amount?

A. As shown in Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, the Company is proposing to spend \$840,000 in the 12 months ending April 30, 2027 test year on Fleet Vehicle Electrification. This sum includes ICE to EV replacements and \$600,000 to install JEMS idle mitigation units on each of 12 bucket trucks (vehicle spec 64) as shown in Exhibit A-104 (QAG-5).

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 pickup truck chassis

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1 and an EV pickup truck chassis is approximately \$40,000, totaling approximately \$240,000
2 for 10 EV pick-up trucks. The ePTO idle reduction units are effective tools in lowering
3 idle hours, fuel costs, and tailpipe emissions on bucket trucks. The addition of these EVs
4 will further the Company's efforts to reduce fuel and maintenance costs, as well as its
5 overall carbon footprint.

6 **Q. Why is the Company requesting only the purchase price difference between an ICE**
7 **vehicle and an EV in this case?**

8 A. Due to these vehicles being part of the replacement plan process, the funding to replace an
9 ICE chassis is already being requested as part of the capital replacement plan. Therefore,
10 the Company is only requesting to add the purchase price difference between a standard
11 ICE chassis and the electrification cost of its replacement unit.

12 **Q. How do these capital expenditures benefit the customers?**

13 A. The vehicle electrification expenditures will benefit the customer in several ways. EVs
14 and plug-in hybrids are expected to lower the Company's overall fuel and maintenance
15 costs as compared to ICE powered vehicles. The EVs proposed also could offer significant
16 potential reductions in greenhouse gas emissions, increasing the Company's carbon
17 avoidance efforts, while providing service to customers with less pollution at lower cost.
18 Lastly, the units proposed for the Test Year will further the Company's learnings on EV
19 best practices, planning, and deployment as it increases fleet electrification.

C. Fleet Expansion Spending

Q. Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, contains a line item related to Fleet Expansion expenditures for HVD. Please explain what this is.

A. The Company intends to make investments of \$648,000 in the 12 months ending December 31, 2025, \$15,170,000 in the 12 months ending December 31, 2026, and \$46,070,000 in the test year to support workforce expansion efforts in Electric Operations. The purchases include pickup trucks with specific upfits that will be used by the Electric Operations substations to perform work related to HVD operations. See Exhibit A-104 (QAG-5). The purpose of this workforce expansion is to continue facilitating the Company's increasing investment in electric distribution infrastructure as outlined in the testimony of Company witness Michael P. Kelly.

Q. What concerns does Fleet Services have if the proposed capital expenditure amounts for expansion are not approved?

A. If the proposed capital expenditure amounts for expansion are not approved, the Company risks stranding labor as some members of the Company workforce that construct and maintain electric distribution infrastructure will be without equipment and vehicles necessary to perform the work.

D. Fleet Business Partner Funded

Q. In the 12 months ending December 31, 2024, the Company funded a business partner funded investment of \$55,000. What is included in this amount?

A. As shown in Exhibit A-12 (QAG-1), Schedule B-5.6, page 4, line 4, column (b), the Company invested approximately \$55,000 to acquire a pickup truck. This unit is used by

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Company personnel responsible for maintaining batteries at the Company's solar renewable generation sites.

Q. How did you determine the needed level of spending for the partner funded equipment?

A. The level of spending represents vehicle costs including tax, title, license and delivery.

Q. How do these capital expenditures benefit the customers?

A. See the direct testimony of Company witness Thomas P. Clark for a summary of the benefits of the Company's solar generation investments.

E. Fleet Tools

Q. What kind of purchases are included in Fleet Tools?

A. Fleet tool purchases include the following: diagnostic equipment, tool sets, ergonomic tooling, and specialty equipment required to properly service and repair fleet vehicles, equipment, and trailers.

Q. What level of expenditures is included in this rate case for Fleet Tools?

A As shown on Exhibit A-12 (QAG-1), Schedule B-5.6, page 4 the Company spent \$280,000 in the 2024 historical year; \$251,000 for the 12 months ending December 31, 2025; \$336,000 for the 16 months ending April 30, 2026; and \$259,000 in the 12 months ending April 30th, 2027, test year on Fleet Garage Tools. A further breakdown of this tooling type per year can be found on Exhibit A-104 (QAG-5).

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

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1 recovery/recycle/recharge machine required to properly service R1234yf refrigerant.
2 Diagnostic tooling is necessary for the repair of most vehicle systems such as the engine,
3 transmission, air bag, lighting, and anti-lock brakes. This tooling requires updates to
4 maintain access to new vehicle models. Electronic service information is required to
5 diagnose vehicle concerns and to follow the manufacturer's recommended repair
6 procedures. Additional tooling such as hydraulic torque wrenches are critical in ensuring
7 that high torque fasteners requiring very high torque applications are properly set and
8 adjusted to manufacturer torque specifications to ensure safe repairs and inspections.
9 Maintenance equipment, such as an R1234yf air conditioning machine, are required to
10 meet Environmental Protection Agency standards for safely recovering and recharging air
11 conditioning systems on newer model year vehicles.

12 **Q. What benefits does this level of Fleet Tools spending provide to customers?**

13 A. Across the state, the Company has 36 locations where Fleet mechanics are permanently
14 stationed to perform their daily work. The Company also has remote sites, training
15 facilities, and jobsite reporting locations where repairs to vehicles and equipment are also
16 performed. The projected Fleet Tools for 2025 spending is approximately \$494,000 for
17 the entire Company, or approximately \$13,700 for each of the 36 locations where
18 mechanics are stationed. The electric allocation of this total is approximately \$251,000.
19 Each year, the Company replaces and updates outdated or unrepairable shop equipment
20 such as floor jacks, diagnostic equipment, tire machines, and welders. The benefit to
21 customers of having tools in good order is less downtime for vehicles and reduced
22 maintenance expenses because the Company is not solely reliant on outside repair shops to
23 complete the work needed to keep vehicles active. Most repair and maintenance items are

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1 performed by the Company's in-house mechanics; therefore, it is imperative that the
2 Company maintain a complete and updated inventory of tools to complete the work
3 required.

4 **Q. Does this conclude your direct testimony in this proceeding?**

5 **A.** Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

MEGAN L. HAYWARD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MEGAN L. HAYWARD
U-21870 DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

2 A. My name is Megan L. Hayward, and my business address is 1945 W Parnall Rd, Jackson,
3 Michigan 49201.

4 **Q. By whom are you employed?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

6 **Q. What is your position with Consumers Energy?**

7 A. I am currently the Director of High Voltage Distribution (“HVD”) System Planning.

8 **Q. What are your responsibilities as Director of HVD System Planning?**

9 A. My responsibilities as Director of HVD System Planning include oversight of capacity and
10 new business engineering activities including planning and design services for the
11 Company’s high voltage electric distribution system, including HVD lines system, HVD
12 and Low Voltage Distribution (“LVD”) substations, and the Metro system.

13 **Q. What is your formal educational experience?**

14 A. I received a Bachelor of Science in Engineering degree in 2006 from Hope College and
15 attended Michigan State University from 2006-2008 for a Master of Science in Engineering.

16 **Q. Would you please describe your previous work experience?**

17 A. I started my career with Consumers Energy in 2016 as a Civil & Structural Engineering
18 Manager leading a team of engineers responsible for the statewide design of projects
19 required for the capital investment plan at Generation facilities. In 2020, I moved to a new
20 role as the Manager of Enterprise Resource Planning, supporting the development and
21 visibility of long-term resource planning across the Company’s utilities. In 2022, this role
22 expanded, and I became the Director of Enterprise Resource and Workforce Planning,

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1 which included setting the workforce planning objectives for the Company. I assumed my
2 current role as the Director of HVD System Planning in 2024.

3 **Q. What is the purpose of your direct testimony in this proceeding?**

4 A. My direct testimony provides an overview of the Company's HVD lines system, its HVD
5 and LVD substations, and its Metro system; and associated capital investments to improve
6 reliability and resiliency of those systems, while serving new customers to support
7 economic development in the state of Michigan. I have organized my testimony as follows:

- 8 (i) A description of the Company's HVD lines system, HVD and LVD
9 substations, Metro system, and System Protection assets, and the Company's
10 strategy for investing in those systems;
- 11 (ii) A description of the HVD lines, HVD and LVD substations, and Metro capital
12 programs and expenditures; and
- 13 (iii) A breakout of each of those capital programs' expenditures.

14 I also discuss and sponsor an exhibit explaining how the Company mapped substation and
15 HVD line assets into voltage and other categories identified in the Electric Asset
16 Categorization ("EAC") report used in the Cost-of-Service Study ("COSS") and discussed
17 in more detail by Company witness Emily A. Davis.

18 **Q. Are you the only Company witness addressing the Company's electric distribution
19 strategy and investments?**

20 A. No. Multiple witnesses are providing comprehensive support for the Company's electric
21 distribution requests. Company witness Michael P. Kelly will provide an overview of the
22 Company's electric distribution strategy and will discuss electric distribution Operating and
23 Maintenance ("O&M") spending. Company witness Jennifer M. Partlan will provide an
24 overview of the Company's historical and planned capital investments in the LVD lines
25 system. Company witness Scott A. McPhail will provide an overview of the Company's

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historical and planned capital investments in the Grid Automation Program. Company witness Daniel A. Schmoekel will provide an overview of the Company's historical and planned capital investments in streetlighting.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-107 (MLH-1)	Consumers Energy Electric Asset Management High Voltage Distribution (HVD) Pole Inspection Specifications;

Exhibit A-108 (MLH-2)	Pole Inspection Plan by HVD Line;

Exhibit A-109 (MLH-3)	Summary Projected Electric Capital Expenditures for the Bridge Period 16 Month Ending April 30th, 2026;

Exhibit A-110 (MLH-4)	Summary Projected Electric Capital Expenditures for the Test Year 12 Months Ending April 30th, 2027; and

Exhibit A-111 (MLH-5)	Electric Asset Categorization Mapping Document.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

Q. How is your testimony organized?

A. Below is a Table of Contents which sets forth the subjects of my testimony.

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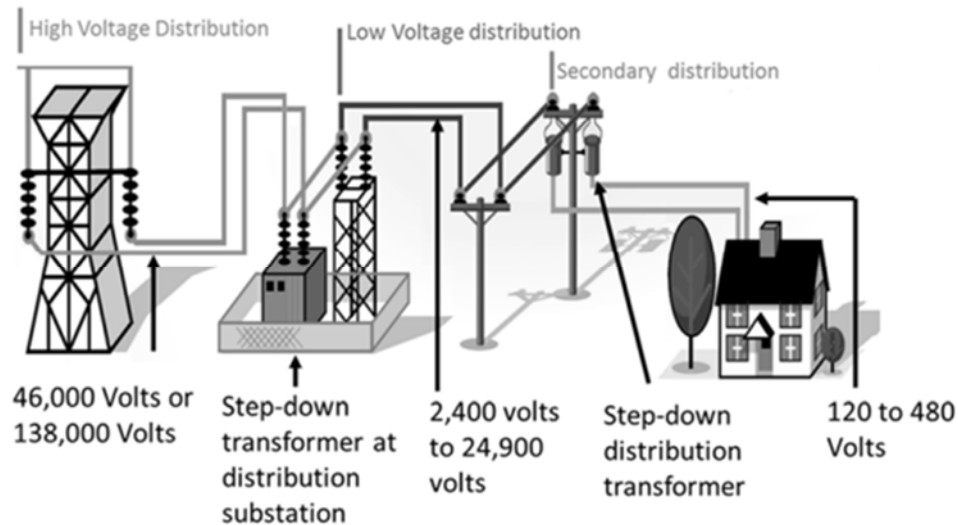
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I. EXECUTIVE SUMMARY

Q. What parts of the Company's distribution system will your testimony address?

A. As discussed by Company witness Kelly, the Company's electric distribution system is comprised of HVD, LVD, and Metro assets. The HVD and LVD systems are shown below in Figure 1. For purposes of this figure, Metro assets are essentially the same as LVD distribution assets.

FIGURE 1
HIGH VOLTAGE AND LOW VOLTAGE DISTRIBUTION SYSTEM OVERVIEW



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1 My testimony will address the current health of the HVD lines system, HVD substations,
2 LVD substations, the Metro system, and System Protection Relays, and explain needed
3 investments in those systems to address asset health; improve system performance; and
4 improve reliability for customers, particularly by mitigating the risk of large customer
5 interruptions. These investments will ensure both the reliability and cost efficiency of the
6 distribution system by proactively addressing, repairing, and replacing assets before they
7 fail and ensuring a reliable and resilient system that can serve electric peak demand. This
8 testimony and associated exhibits outline how projected investments in those systems
9 deliver on the Company's 2023 Electric Distribution Infrastructure Investment Plan
10 ("Reliability Roadmap," formerly known as the "2023 EDIIP"), an amended version of
11 which is included in this case as Exhibit A-129 (MPK-19). The capital investments outlined
12 in this testimony are described in detail by sub-program and investment category, with
13 discussion on the purpose of the program and the basis for the investment. Specific
14 investments identified in the Reliability Roadmap include:

- 15 • Mitigating the risks from obsolete pole tops and deteriorated poles through
16 investment in **HVD lines**;
- 17 • Mitigating the risks from deterioration through securing, inspecting, and
18 upgrading **HVD and LVD Substations**;
- 19 • Mitigating the risks from deterioration through inspecting and upgrading the
20 civil and electrical components of the Company's **Metro** assets;
- 21 • Enhancing and modernizing the protective system with **System Protection**
22 **Relays**, and
- 23 • Ensuring the HVD System can serve electric peak demand, new
24 interconnections, and support economic development through **HVD Load**
25 **Growth & Interconnections**.

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Please note that throughout my testimony I will often refer to the HVD lines system and HVD substations collectively as the “HVD system.”

Q. Please provide an overview of the HVD system.

A. Consumers Energy’s HVD system consists of HVD lines and substations that distribute electricity to its LVD substations. Information about the size of the system is shown below based on HVD line miles and number of substations. Additionally, the HVD system includes a system of protective relays, which I discuss separately in the section of my direct testimony on the System Protection sub-program.

HVD Lines System:		HVD & LVD Substations:	
4600 Overhead Miles	4400 Miles of 46kV	1138 Total Substations	144 HVD Subs
	200 Miles of 138kV and 69kV		164 Strategic Electric Customer (“SEC”) Subs
23 Underground Miles	19 Miles of 46kV		830 LVD Subs
	4 Miles of 138kV		

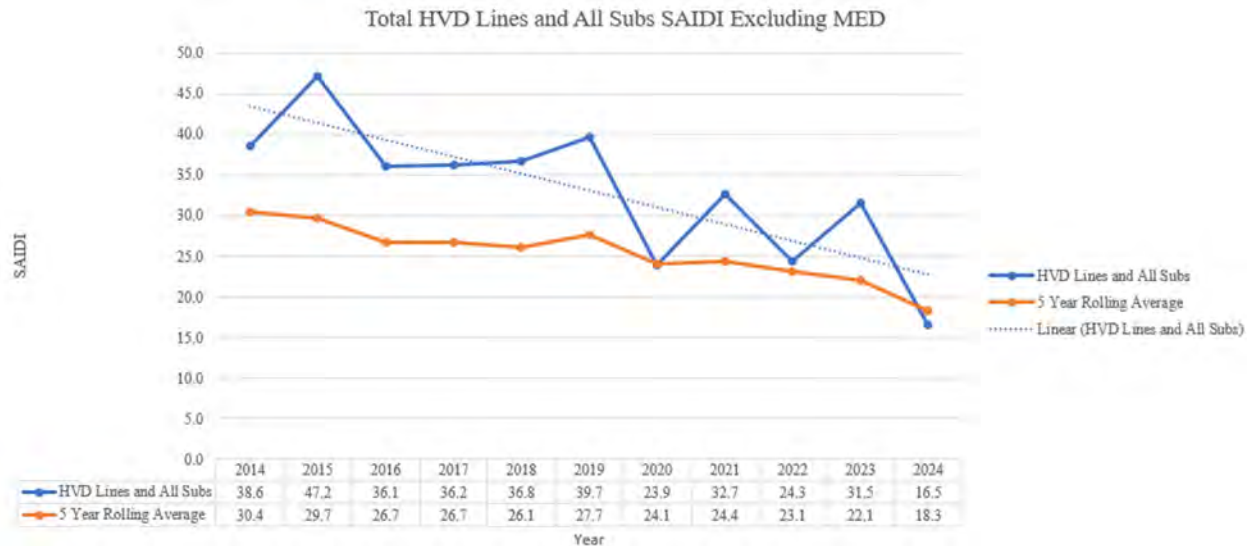
Q. Why must the Company make investments in the HVD system?

A. HVD lines and HVD substations are the backbone of the Company’s distribution system, which means outages on the HVD system can lead to widespread interruptions for thousands of customers from a single incident. To mitigate against this risk, the Company must invest in the HVD system to ensure that the backbone remains resilient, able to quickly restore customers if outages occur, and to minimize the occurrence of outages in the first place. The Company has generally been successful at this over the years, meaning HVD assets do not usually contribute a major share of the Company’s total System Average Interruption Duration Index (“SAIDI”). Indeed, historical investment levels in the HVD system have driven an improving trend line of overall HVD system performance in recent years.

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Figure 2 below illustrates a gradual reduction in SAIDI. However, the risk of large HVD outages with a correspondingly high impact on SAIDI is always present if HVD assets begin to deteriorate. On average, when excluding major event days (“MEDs”), a single outage at an HVD substation or on a HVD line is 50 times more impactful than an LVD line outage, both in terms of SAIDI and number of customers impacted. Without proper attention to the HVD system, SAIDI impacts will quickly increase, to the detriment of customers. A reliable and resilient system backbone is required to continue the Company’s downward and improving trend in SAIDI performance.

FIGURE 2



Unfortunately, the asset health of many major components within the HVD system is deteriorating, with many of these assets well beyond their intended lifecycle. To ensure that this backbone infrastructure remains reliable and resilient, the Company monitors and assesses the asset health of HVD system components, so that areas of risk can be addressed proactively through investments. Increased investment in the HVD system, at the levels identified in the Company’s Reliability Roadmap, is necessary to sufficiently reduce asset

1 risk on the HVD system, ensure a resilient backbone, and to contribute to further reduced
2 SAIDI.

3 Finally, failed assets can present safety risk to the public and to Company
4 employees, particularly when they create situations where people can be exposed to high-
5 voltage energized equipment. Investments to address asset health concerns therefore
6 mitigate public safety risks.

7 **Q. Can you further elaborate on how HVD lines and substation investments align with**
8 **the Reliability Roadmap?**

9 A. As Company witness Kelly explains, the Reliability Roadmap includes increased
10 investment in various areas, including the HVD system, necessary to reduce asset health
11 risk to acceptable levels and reduce the risk of future outages. The investments identified
12 throughout my testimony are aligned with those spending levels defined in the Reliability
13 Roadmap, designed to ensure that the HVD system continues to provide a reliable and
14 resilient backbone infrastructure, critical to supplying the LVD system. These investments
15 will also help continue the downward trend in HVD SAIDI that the Company has seen in
16 recent years, as shown in Figure 2 above.

17 **Q. What is the Company's approach for investing in the HVD system?**

18 A. The Company monitors the health of its HVD assets through a variety of data points from
19 various maintenance and inspection programs. Through these processes, the Company
20 determines the asset health risk for HVD assets, which informs investment decisions in
21 HVD capital projects. These capital investments proactively address risk on HVD assets
22 through repair, replacement, or upgrade prior to asset failure. A significant proportion of
23 the Company's HVD investments are directed toward identified asset health issues and

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1 issues identified during inspections; this is the basis for the Company's investment in its
2 HVD reliability programs. All of these investments are intended to ensure the continued
3 reliable and resilient operation of the HVD system. It is important to note that HVD system
4 improvements may not always be captured in reduced SAIDI from existing levels, but there
5 are still substantial customer outage minutes to avoid by preventing future failures from
6 occurring.

7 When needed, the Company also expands and/or modernizes the grid to serve
8 growing loads from commercial and industrial ("C&I") customer base as they electrify their
9 businesses. All HVD capital investments are identified and planned to support the overall
10 objectives and strategy outlined in the Company's Reliability Roadmap.

11 **Q. Why must the Company invest in LVD substations?**

12 A. As with HVD system assets, LVD substations play a crucial backbone role in the
13 distribution system, since they directly feed the LVD circuits that serve customers. While
14 HVD substations often serve many downstream communities, LVD substations often serve
15 a single community or a more focused local area, but this means that a given LVD substation
16 can have a major impact on that single community. Outages on LVD substations lead to
17 significant interruptions for customers when they happen, and as I discuss in my direct
18 testimony many of the Company's LVD substations have asset health risks that must be
19 addressed to prevent those outages.

20 **Q. Why must the Company invest in the Metro system?**

21 A. The Metro system is dedicated to providing underground electric service in six key
22 downtown areas in the Company's service territory and is critical for the economic health
23 and development of the cities that it serves. As with HVD lines and with substations, the

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Company must ensure that the Metro system provides the needed electrical backbone for these downtown areas and must invest accordingly in order to support the asset health of the Metro system.

Q. How are the HVD lines, substations, and Metro system capital investments summarized in this proceeding?

A. The historical year is calendar year 2024. The bridge period consists of the 16 months beginning January 1, 2025, and ending on April 30, 2026. The test year is the 12 months beginning May 1, 2026, and ending on April 30, 2027.

Q. Please summarize the HVD lines, substations, and Metro system capital expenditure plan in this filing by historical year, bridge period, and test year.

A. The HVD lines, substations, and Metro system capital expenditures described in my testimony are summarized in Figure 3 below. Throughout my direct testimony, I will explain how these proposed investment levels will deliver meaningful benefits for customers through specific projects on the system.

FIGURE 3
HVD/SUBSTATIONS/METRO CAPITAL EXPENDITURE SUMMARY

	Bridge Period	Test Year
All Programs	\$542,846,000	\$417,546,000

Q. What specific HVD system, LVD substation, and Metro projects does the Company expect to invest in during the bridge period and test year?

A. Specific projects are identified in Exhibits A-109 (MLH-3) and A-110 (MLH-4). The exhibits include projects identified with scope, cost, location, benefit type, and benefits. The two quantitative benefit types are:

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- Customer outage minutes avoided: Product of the number of customers that experience an extended outage of electrical service and the duration of outage measured in minutes.
- Customers impacted: Number of customers served by a project. In the case of commercial customers, the customers impacted are treated as “1.”

Note that not all projects have quantitative benefits. Some projects may be completed for regulatory compliance, based on the Company’s obligation to serve customers, or other reasons. Company witness Kelly provides more details about how the quantitative benefits are calculated. Throughout my direct testimony, I will explain more about the specific benefits of each investment sub-program.

II. HVD SYSTEM STRATEGY

Q. What challenges are faced by the HVD system?

A. The HVD systems are considered the backbone infrastructure of the electric distribution system because they connect the electric transmission system to the Company’s LVD system. When outages occur on the HVD system, this backbone characteristic means interruptions to customers can be widespread and long in duration. To mitigate this, the HVD system needs to be resilient, which is why it is largely a looped system with built-in redundancies capable of either continuing service to customers or at least minimizing the number of impacted customers due to the failure of any single component. To maintain redundancy and ensure that this backbone infrastructure remains strong, the Company monitors and assesses the asset health of HVD system components, so areas of risk can be addressed proactively. This practice is discussed in detail in the Reliability Roadmap.

Historical investment levels in the HVD system have improved the trend of overall HVD system performance as illustrated in Figure 2. However, significant variation in SAIDI contribution can also be seen from one year to the next, highlighting the significance

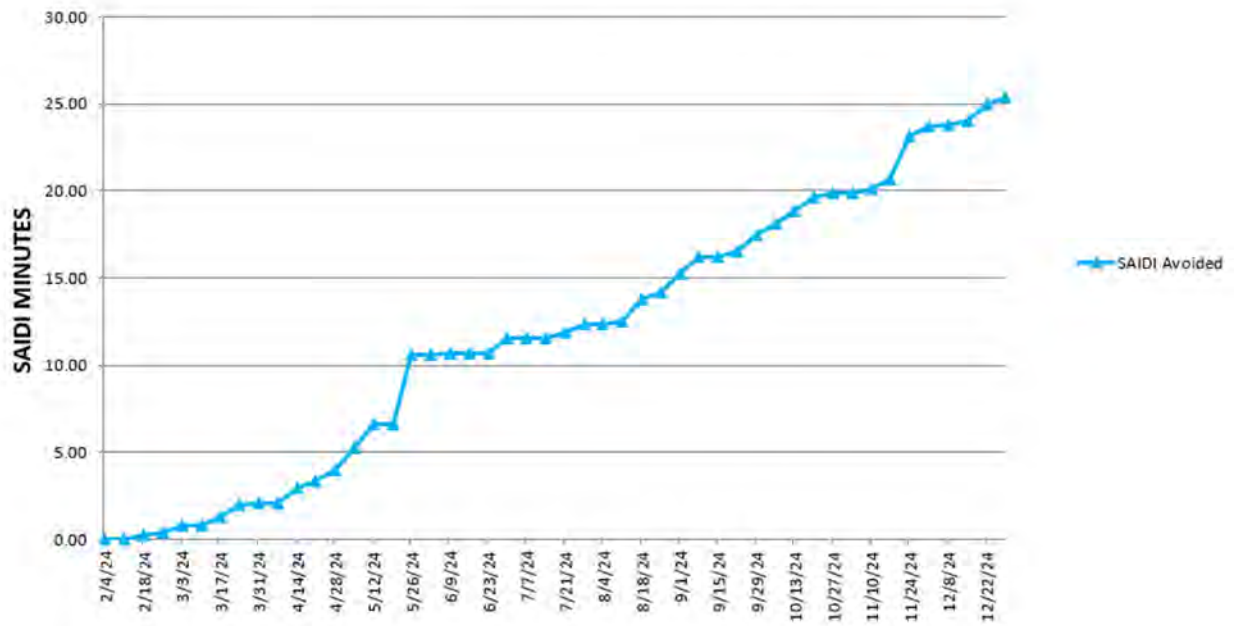
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1 of HVD system outages that do occur. The Company continues to face deteriorating asset
2 health year-over-year for many of its HVD assets, which threaten their ability to continue
3 to perform as a reliable and resilient backbone for the entire system.

4 **Q. How is the Company able to substantiate that its HVD assets face declining asset**
5 **health?**

6 A. This is clearly supported by the annual findings from the Company's annual inspections,
7 maintenance, and diagnostic test of HVD assets that a) identify anomalies that must be
8 addressed prior to failure; and b) provide key insights into asset health and how assets are
9 performing. In 2024, the Company's inspections identified anomalies that, if not addressed,
10 would have resulted in 25.3 SAIDI minutes, as shown in Figure 4 below. This is also
11 discussed in more detail later in my direct testimony when discussing the HVD Lines and
12 Substations Demand Failures sub-program. In this figure, each data point reflects one week
13 of activity. During each week, the Company mitigates any defects identified during
14 inspections that would fail within months and cause interruptions to customers if not
15 addressed (anomalies are typically addressed within one to two weeks of identification).
16 The Company then calculates the SAIDI minutes that would result if the affected asset failed
17 and caused interruptions to customers. The blue trend line indicates the cumulative avoided
18 SAIDI throughout the year.

FIGURE 4
SAIDI avoided through correction of defects



For comparison, the equivalent avoided SAIDI from correcting anomalies was 16.8 minutes in 2023, indicating a worsening trend in HVD asset health, as the Company is finding more high-priority anomalies year-over-year. Historically, the equivalent amount was only about 10 avoided SAIDI minutes per year. This is one demonstration that HVD asset health is worsening, as the Company, through better use of technology and inspection techniques, is finding increasing levels of these narrowly avoided failures. Without increased proactive investment, anomalies will increase to a level where the Company cannot proactively mitigate failures, and significant interruptions to customers will result.

Q. How do inspections, maintenance, and diagnostic testing provide further insights into asset performance and health beyond these avoided interruptions to customers?

A. These key data points are collected and reviewed to build an asset health model that is used as a tool in determining capital investments and maintenance plans and establishing a general trend of asset health. The Company uses this asset health model to evaluate the

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1 assets on its system and identify all assets that face declining asset health, using a variety of
2 data points to assess risk levels. The asset health model considers multiple inputs like asset
3 type, manufacturer, condition, age, actual outages, and level of degradation collected about
4 the asset during inspections, maintenance, and/or annual diagnostic testing to provide a
5 holistic view of the asset's health. By applying this asset health model process to its HVD
6 assets, the Company can document which assets face declining health and design projects
7 to fix these issues; projects proposed in the instant case, particularly in the Reliability
8 sub-programs, have been identified in this way.

9 Note that while age is an input in the asset health model, it is not a sole determining
10 factor used to initiate a project for replacement or retirement. For example, age is an
11 important factor in evaluating substation transformer banks that are over 50 years old, as
12 age directly impacts how internal components break down. Identifying transformers over
13 50 years of age helps the Company prioritize replacements among multiple transformers of
14 differing ages when they otherwise have the same overall health as determined by
15 inspections and diagnostic testing. In other words, when multiple transformer banks have
16 the same health score from inspections and tests, the Company will replace both
17 transformers, but the transformer over 50 years of age will be conducted before the one that
18 is 30 years old.

19 It is important to note that the asset health model is meant to identify assets with
20 elevated risk levels, but it is not meant to predict specific future failures and identify a date
21 and time when they will definitely fail. The asset health model gives indications of where

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1 problems will likely occur so the Company can begin planning ahead and know where to
2 focus its attention to address the biggest risks on the system.

3 **Q. Please describe how the asset health model works in more detail.**

4 A. As stated above, the purpose of the asset health model is to identify where the Company has
5 elevated asset health risk so the Company can plan ahead to address issues. Planning ahead
6 is essential because many projects have long lead times, and planning must begin multiple
7 years in advance; for many projects, the Company must first obtain rights of way and order
8 long lead time materials well before design or construction can begin.

9 For HVD, the asset health model includes lines and substations and their
10 components, as well as the relaying assets that are the subject of the System Protection
11 sub-program discussed later in my testimony. For each type of asset, the asset health model
12 incorporates critical asset factors such as inspection results and testing results, plus known
13 manufacturing issues that affect certain types of equipment. In the case of substation
14 transformers and breakers, asset age is also one of the factors included in assessing risk;
15 because these assets have a known correlation between age and failure, the Company would
16 replace a 50-year-old transformer before a 30-year-old transformer, all else being equal.

17 For each asset on the system, these inputs are used to generate an asset health score.
18 An HVD line's asset health score combines multiple data points that include if it is a radial
19 line or not, potential customer impact, type of conductor, configuration, number of trips,
20 number of lockouts, red tagged poles, and victor insulators. Figure 5 below shows the point
21 value assigned to each factor of a line segment that helps generate its overall health score,
22 and Figure 6 shows a sample calculation of a line segment health score.

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FIGURE 5
HVD LINE ASSET HEALTH WEIGHTING

Radial line	Points per mile	5
Customers	Points per 1,000	2
Obsolete conductor	Points per mile	5
Unshielded conductor	Points per mile	1
Top 25 contingency	Yes	0
Trip	Points per trip	1
Lockout	Points per lockout	2
Rush red tagged pole	Points per pole	2
Planned red tagged pole	Points per pole	1
Victor insulators	Point per insulator	0.3

FIGURE 6
HVD SAMPLE HEALTH SCORE BY LINE SEGMENT

Line Name	Total Point	Radial	Customer Impact	Obsolete Conductor	Unshielded	Victor Insulators	Red Tagged Poles	Lockout
Line Segment A	133	30	6	0	0	60	25	12
Line Segment B	100	0	10	50	10	0	30	0
Line Segment C	86.6	25	5	0	0	3.6	45	8

1 An HVD substation's asset health score combines the scores of multiple components within
2 the substation. Figure 7 below shows an example of an asset health score for a substation,
3 showing how multiple component scores total the station score. Figure 8 shows how
4 transformer factors impact the total score for the transformer.

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FIGURE 7
HVD SAMPLE HEALTH SCORES FOR SUBSTATIONS

Category	Points per Occurance	Sub A	Sub B	Sub C
AC/FP/REC Wound	25	0	0	0
Age 50+	20	1	1	1
Oil or N2 Leaks	10	1	1	0
Transformer Internal Infrared	10	0	1	0
DGA Score	20	1	0	0
Brand A Bushing Issue	15	1	0	0
Brand B Bushing issue	5	0	0	0
IR P1/P2	20	0	1	0
Doble or Elec Test Issues	15	0	1	0
Transformer & Bushings Total		85	75	20
REG/LTC TOA R3/4	25	1		
IR P1/P2	20			
REG/LTC Total		25	0	0
OCB > 50 Yrs; GCB > 25 Yrs	5	7	3	1
3PH Reg/LTC Demand Order	10	1		
BRKR Oil or SF6 Gas Quality/Leaker	15		1	1
IR P1/P2	15			
Maint/RP Priority List	10			
Oil and Gas Circuit Breakers Total		45	30	20
99 & Cap Bank CSWs/VSW Issues	15	1		
SPT Watch List	10	2	1	1
Str & Concrete	5	1		
Other	5			
IR P1/P2	15		1	1
Ops Limiting Equip	20	1		
Station & Other Totals		60	25	25
Total Score Normalized		100	66.66667	33.33333
Gross Total		195	130	65

FIGURE 8
TRANSFORMER ASSET HEALTH WEIGHTING

Factor	% of Total Score
Age over 50+ years	14%
How the Transformer is Wound	18%
Nitrogen Gas or Oil Leaks	7%
Allis Chalmers Infrared	7%
Dissolved Gas Analysis	14%
Bushing Type	4-14%
Electric Testing Results	11%

1 **Q. How are asset health scores used by the Company once generated?**

2 A. In general, the Company uses asset health scores to rank lines and substations for the
3 prioritization and development of projects. Since assets with higher scores are at greater
4 risk of deterioration and failure, they are prioritized for projects to fix identified reliability
5 issues. Asset health scores indicate not only *that* an asset faces deteriorating health, but also
6 *what* is driving the issue, and this helps determine what kind of project is appropriate. For
7 example, an HVD line may have a high score simply due to the presence of some
8 deteriorating poles, so the Company would respond to that by replacing those poles. If the
9 line had a score indicative of various other equipment issues, then a full line rebuild may be
10 more appropriate.

11 However, the Company does not necessarily strictly “go down the list” in
12 prioritizing and scheduling HVD projects. Many large HVD projects have multi-year
13 schedules, with a series of steps that must be completed in order, and this affects when
14 projects can be executed. For example, the substation with the highest asset score today
15 may require a full rebuild. Rebuilding that substation may require the Company to acquire
16 new real estate first and procure long lead time materials before construction can take place,
17 meaning construction may not be possible for a few years. In the meantime, the substation
18 with the fifth-highest asset score today may be fixable through a quicker project that can be

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1 done this year. In this situation, the Company would be completing a technically
2 lower-ranked project before a higher ranked one, due to timing issues. Additionally, the
3 multi-year nature of some projects means that a future project may move up or down in
4 prioritization while it is in development as information about other asset health needs come
5 to light. This is one reason why an asset health model is useful in the first place: the
6 Company can optimize asset health to reflect shifting needs.

7 Furthermore, the Company often tries to coordinate projects to create efficiencies,
8 so projects may be moderately reprioritized to take advantage of keeping a workforce in a
9 specific area, or to coordinate with other kinds of infrastructure work being done by state
10 and local governments.

11 **Q. If the Company does not invest in the HVD system at the levels proposed in the instant**
12 **case, what risks will this create for the Company's system?**

13 A. As noted earlier in my direct testimony, a single outage at an HVD or LVD substation or on
14 an HVD line is 50 times more impactful than an LVD line outage, both in terms of SAIDI
15 and of customers impacted. The Company has documented an increase in the number of
16 anomalies found on the HVD system, and the Company's asset health modeling gives the
17 Company detailed insight into which assets need investment most urgently. If the Company
18 does not make the needed investments in the HVD system, more assets will simply be run
19 to failure, and HVD SAIDI would degrade; again, note that in 2024 the Company had HVD
20 assets that were within months of failures that would have increased SAIDI by over
21 25 minutes. Throughout my direct testimony in the respective sub-program sections, and
22 in my exhibits, I will explain how specific investments will deliver clear reliability benefits
23 to customers, particularly through future customer outage minutes avoided through the

1 investments. In the aggregate, planned investments will not only *prevent* future large-scale
2 interruptions to customers, but they will also *reduce* SAIDI on a net basis.

3 **Q. How has the Company determined that a single HVD outage is similar in impact to**
4 **50 LVD outages?**

5 A. In 2024, the average LVD outage on the Company's system impacted 38 customers and
6 contributed 0.003 minutes of SAIDI, while HVD lines and substation outages on the
7 Company's system, on average, impacted 1,863 customers and contributed 0.18 minutes of
8 SAIDI. This data highlights the impact that each HVD line and substation outage has on
9 the system; while they have fewer total outages events, the outages that do occur are much
10 more impactful than outages on the LVD distribution system.

11 **Q. What role does the Company's inspections play in this process of identifying HVD**
12 **investment needs?**

13 A. As stated above, inspections provide critical inputs into the asset health model, helping the
14 Company identify HVD investment needs in the medium to long term. Inspections are also
15 crucial for identifying already failed components (which are then fixed in the HVD Lines
16 and Substations Demand Failures sub-program) and in identifying components that present
17 a near-term risk of failure (which are typically then addressed in the HVD Lines Reliability
18 or HVD Substations Reliability sub-programs). In these situations, the Company develops
19 a project to address the problem immediately or in the very short term; this kind of work
20 does not go through the asset health model because there is no need to assess longer term
21 risk when the asset has already failed or is about to fail.

1 **Q. Does the Company make any investments in the HVD system that are not directly**
2 **related to asset health or reliability?**

3 A. Several HVD investment sub-programs address other important concerns. The HVD system
4 plays a critical role in supplying electricity to large C&I customers that play an essential
5 role in Michigan's economy. As Michigan attracts new large C&I customers, their demand
6 for electricity will require expansion of the HVD system in certain areas, an issue that was
7 discussed in the Reliability Roadmap. These needs are most specifically addressed in the
8 Company's HVD Strategic Customers New Business and Metro New Business
9 sub-programs, discussed later in my testimony. Issues related to load growth are also
10 addressed in the HVD Lines and Substations Capacity sub-program and the LVD
11 Substations Capacity sub-program, and the HVD Lines and Substations Capacity
12 sub-program also addresses other important needs related to the functioning of the grid, such
13 as interconnections with the transmission system.

14 Finally, the Demand Failures and Asset Relocations sub-programs addressed later
15 in my direct testimony deal with emergent issues on the system that may not always be
16 related to asset health.

17 **III. LVD SUBSTATIONS STRATEGY**

18 **Q. Please provide an overview of the Company's LVD substations.**

19 A. The Company has approximately 830 LVD substations in its system to step down voltage
20 from the HVD lines system to the LVD lines system. LVD substations are supported by the
21 Company's fleet of mobile substations, which provide continuity of electric service to
22 customers during planned and unplanned LVD substation outages where redundancy is not
23 present or load transfers to adjacent substations are not available.

1 **Q. What challenges are faced by the Company's LVD substations?**

2 A. As with the HVD substations, the Company's LVD substations face similar asset health
3 risks that the Company must address in order to maintain continued reliability for customers,
4 especially because LVD substations do not always have the same levels of redundancy as
5 HVD substations. As with the HVD substations, LVD substations have their own asset
6 health models to inform investments, which I will address in more detail in the section of
7 my direct testimony covering the LVD Substations Reliability sub-program. LVD
8 substations face some unique challenges that are addressed through corresponding
9 investment categories that I will discuss in my direct testimony, such as animal intrusions
10 and the use of obsolete Allis Chalmers transformers, which both drive investments in LVD
11 substations.

12 Additionally, the locations of LVD substations on the system – often in communities
13 relatively close to load – means that LVD substations are particularly susceptible to the
14 impacts of localized load growth, which drives the need for investments in LVD Substations
15 Capacity.

16 **IV. METRO SYSTEM STRATEGY**

17 **Q. Please provide an overview of the Metro system.**

18 A. The Metro system provides underground distribution service in the downtown areas of six
19 cities in the Company's service territory: Battle Creek, Flint, Grand Rapids, Jackson,
20 Kalamazoo, and Saginaw. Much of the Metro infrastructure was first installed in the 1910s
21 through the 1950s to accommodate electric distribution in already busy downtown areas.
22 Metro infrastructure is used, both in the past and today, to manage the density of downtown
23 city centers, facilitate electrical repairs, and for aesthetics.

1 The primary benefit of the Metro System is to address space limitations where
2 numerous utilities (electric, gas, telecommunications, water, and sewer) must use limited
3 right-of-way (“ROW”) in public streets and alleys, especially because high-rise buildings
4 have greater utility needs than in lower density areas. The Company’s Metro planning group
5 focuses solely on these key downtown areas, reflecting the Company’s commitment to
6 investment in Michigan by dedicating specific attention to these areas of economic growth.

7 **Q. What challenges are faced by the Metro system?**

8 A. As with the HVD system and LVD substations, the Metro system also faces asset health
9 risks that the Company must address to ensure continued electric reliability for customers
10 in those six downtown areas. The Metro system has its own asset health model, which I
11 will discuss in more detail when addressing the Metro Reliability sub-program later in my
12 direct testimony. The Metro system does not face as many asset health challenges as other
13 parts of the system, and Metro Reliability investment is remaining relatively flat.

14 On the other hand, new economic development projects in some of the downtown
15 areas are necessitating increased investment in the Metro New Business and Metro Asset
16 Relocations sub-programs, which I will discuss later in my direct testimony.

17 **V. CAPITAL SPENDING PROGRAMS**

18 **Q. How does the Company classify its HVD capital investments?**

19 A. As explained by Company witness Kelly, the Company makes capital investments under
20 two broad classifications, *planned* and *unplanned*. Each of these classifications include
21 capital programs addressed in my direct testimony, as outlined in Figure 9 below. Each
22 classification corresponds to one or more capital programs, which are in turn divided into
23 constituent sub-programs and investment categories.

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FIGURE 9
PROGRAM CLASSIFICATION DESCRIPTIONS & HVD SUB-PROGRAMS

Classification	Description	HVD Programs included
Planned	Investments planned to proactively improve grid reliability through capacity upgrades and investments in new tools and technology	Reliability, Capacity, “Electric Other”
Unplanned	Demand-driven and customer-driven needs	New Business, Demand Failures, Asset Relocation

Q. Please summarize the HVD capital expenditure plan in this filing.

A. In this filing, the Company is projecting to spend \$417,546,000 in capital projects on the HVD system, substations, and the Metro system in the test year, and \$542,846,000 in the bridge period. This investment plan is summarized by capital program in Figure 10 below. Increases in the various program areas are covered in their respective sections later in my testimony detailing the need to increase funding and how customers benefit from the projected level of spending.

FIGURE 10
HVD/SUBSTATIONS/METRO CAPITAL EXPENDITURES AND BENEFITS BY PROGRAM (\$000s)

Work Type	HVD Program Area	2024 Actuals	Bridge Period	Test Year
Planned	Reliability	\$ 110,315	\$ 337,137	\$ 273,161
	Capacity	\$ 53,050	\$ 70,569	\$ 51,699
	Electric Other	\$ 896	\$ 447	\$ 294
Unplanned	New Business	\$ 69,024	\$ 96,498	\$ 51,777
	Demand Failures	\$ 23,201	\$ 20,882	\$ 19,311
	Asset Relocation	\$ 12,265	\$ 17,291	\$ 21,304
Total		\$ 268,751	\$ 542,824	\$ 417,546
Benefits				
Projected Total Customer Minutes Saved			90,111,949	77,608,571

1 **Q. What capital projects does the Company expect to invest in during the bridge period**
2 **and test year?**

3 A. A comprehensive list of currently identified Company HVD projects and associated
4 expenditures for the bridge period is provided in Exhibit A-109 (MLH-3), and a list of
5 currently identified projects and associated expenditures for the test year is provided in
6 Exhibit A-110 (MLH-4). Detailed discussion on each capital program and sub-program is
7 provided in the respective sections of my direct testimony.

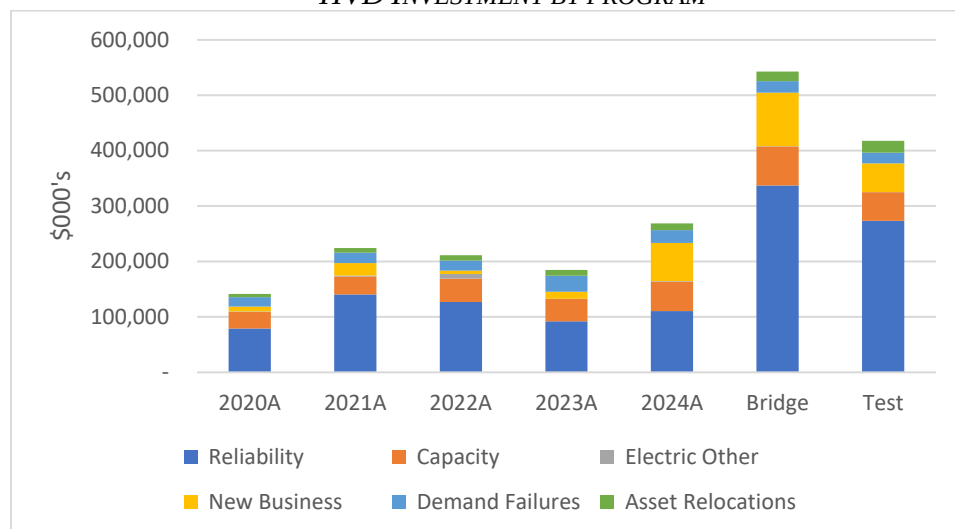
8 **Q. Are contingency expenses included in any of the projected capital expenditures**
9 **included in your testimony?**

10 A. No. Contingencies are not included in the projected capital expenditures.

11 **Q. How does the HVD capital expenditure plan in this filing compare to historical**
12 **investments?**

13 A. An overview of historical HVD capital expenditures by program from 2019 through 2024
14 and projected HVD expenditures for the bridge period and test year are shown in Figure 11
15 below.

FIGURE 11
HVD INVESTMENT BY PROGRAM



1 **Q. Why are investment levels higher in the bridge period and test year compared to recent**
2 **historical levels?**

3 A. As discussed above, the Company has increased its investment levels to align with the levels
4 established in the Reliability Roadmap to be able to deliver on its reliability goals. To ensure
5 reliability and resiliency, the Company must focus on hardening and improving the
6 performance of assets in poor health on the HVD system like poles, wire, breakers, and
7 transformers. This reliability spending allows the Company to address asset health risk
8 proactively and keep assets within their intended useful lifecycle. The goal with reliability
9 is simple: fewer and shorter outages for customers. Additionally, the Company has
10 increased investment relative to historical levels in the HVD Strategic Customers New
11 Business sub-program in order to meet the needs of new and expanding C&I customers, an
12 issue discussed in the Reliability Roadmap. Finally, it is important to note that the bridge
13 period is 16 months long, so total spending is higher in absolute terms than in the other
14 12-month periods shown in the chart.

15 **Q. Are there any general principles that govern how HVD assets are identified so the**
16 **Company can develop targeted projects for those assets?**

17 A. In general, projects are identified using data inputs in the asset health model, as discussed
18 earlier in my direct testimony. The Company performs quarterly operating reviews
19 (“QORs”) of the asset health of components on the system based on information gathered
20 through its many inspections and maintenance activities. Gathered data informs the
21 Company on an asset’s health based on likelihood, consequence, and severity of an asset’s
22 failure, also known as that asset’s risk. When assets are identified as being at-risk, the
23 Company develops projects to address that risk proactively. The QOR lets the Company

1 monitor shifts in asset risk and ensures continued investment in the correct places based on
2 the latest asset information.

3 **Q. When the Company identifies assets that are at risk and require investment, how does**
4 **the Company identify and validate that HVD capital investments are reasonable and**
5 **prudent for customers?**

6 A. For many projects, the Company considers its proposed electric distribution investment
7 against alternatives and develops a “concept approval” to test and demonstrate why the
8 selected project is reasonable and prudent, as discussed in more detail in the direct testimony
9 of Company witness Kelly. As he discussed, Company projects are generally selected using
10 the “least-cost, best-fit” principle. Through this vetting and concept approval process, the
11 Company ensures that it has a strong and robust justification for electric distribution projects
12 that are selected for implementation. The general structure of a concept approval includes
13 the following:

- 14 1. Identification of the system risk;
- 15 2. Identification of alternatives to address the system risk;
- 16 3. Determination of costs and benefits of the alternatives;
- 17 4. Selection of best alternative;
- 18 5. Approvals; and
- 19 6. Revisions, where necessary.

20 **Q. How do customers benefit from the concept approval process?**

21 A. The concept approval process provides a rigorous approach and governance structure to
22 identifying HVD system problems and needs, alternative solutions, and recommended

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alternatives. It provides for peer review and management oversight to ensure that the Company's investment plans are well justified, reasonable, and prudent for customers.

Q. How are these projects justified as reasonable and prudent investments for the customer?

A. As mentioned above, an asset's health is identified through the Company's various health models which leads to the development of a concept to address any asset health concern. This process ensures that the Company continues to prioritize work based on the assets that are in poor health and represent the greatest risk to system performance. Conversely assets near failure as identified during regular inspection of the HVD system that need to be addressed in a timely manner to prevent customers from experiencing an outage do not follow the concept approval process because there are only two options: replace the asset prior to failure or replace it after it fails which causes an outage to customers. As discussed in the HVD system overview, running assets to failure without doing proactive work would result in a significant increase to HVD system SAIDI. The increase in proactive spending allows the Company to address system health and degradation before customers experience outages. These system defects are prioritized according to their risk to system operations and customer reliability and executed to the greatest efficiency to prevent an actual failure.

VI. **HVD SUB-PROGRAM SPENDING DETAILS**

A. **Planned Spending Programs**

1. **Reliability**

Q. **Please describe the Reliability sub-programs.**

A. The overall purpose of the Reliability Program is to ensure the long-term safe and reliable operation of the distribution system, as described by Company witness Kelly. In my testimony, I will address eight HVD Reliability sub-programs:

- HVD Lines Reliability
- HVD Substations Reliability
- Transformer Bank Replacements and Substation Rebuilds
- LVD Substations Reliability
- LVD Substations Rehabilitation
- Metro Reliability
- Metro Rehabilitation
- System Protection

a) **HVD Lines Reliability**

Q. **Please explain what projects, activities, and other types of work are accomplished by expenditures in the HVD Lines Reliability sub-program.**

A. HVD Lines Reliability investments are intended to address deteriorated HVD line assets that have been assessed to be in poor health, mitigating and reducing the contribution of the Company's HVD lines to SAIDI and improving their resiliency. Work in the HVD Lines Reliability sub-program consists of seven investment categories:

- HVD line rebuilds

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- Pole top rehabilitation miles
- Individual pole top replacements
- Pole replacements
- Switch replacement projects, including supervisory control and data acquisition (“SCADA”) additions
- Line sensor deployments
- ROW Acquisition for HVD line rebuilds

Each project in this sub-program is customized to address the particular issues on individual poorly performing assets and deteriorated lines, based on an asset’s, or collection of assets’, risk to system performance. Line sensors and ROW acquisition were new investment categories in this sub-program in Case No. U-21585 in 2024. Line sensors were historically in the HVD Lines and Substations Capacity sub-program but were transferred because their main function is to improve the reliability monitoring of the system and assist with quick identification of faulted line segments. ROW acquisition for reliability projects was also historically in the HVD Lines and Substations Capacity sub-program, but was transferred in order to better align the costs of line rebuilds with the actual work.

Q. Has the scope of the HVD Lines Reliability sub-program changed since Case No. U-21585 was filed?

A. Yes. In Case No. U-21585 and prior cases, the Company had a sub-program called HVD Lines and Substations Rehabilitation, which included various types of investments focusing on line and substation assets that were assessed to be at risk of imminent failure. Work related to HVD lines that had been in that former sub-program has been transferred to HVD Lines Reliability in the instant case, so that all investments addressing the reliability of HVD lines is now within one sub-program.

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1 Other work that was formerly included in the HVD Lines and Substations
2 Rehabilitation sub-program was transferred to the HVD Substations Reliability
3 sub-program, as discussed later in my direct testimony. The remaining work that was
4 formerly included in the HVD Lines and Substations Rehabilitation sub-program is now
5 included in the Transformer Bank Replacements and Substation Rebuilds sub-program, as
6 also discussed later in my direct testimony.

7 **Q. How has this transfer of work from one sub-program to another affected the**
8 **investment categories in the HVD Lines Reliability sub-program?**

9 A. The pole replacement and switch replacement investment categories in the HVD Lines
10 Reliability sub-program now have a larger volume of work in them, because they now
11 include work that was previously done in the former HVD Lines and Substations
12 Rehabilitation sub-program. The individual pole top replacements investment category is
13 new to this sub-program in the instant case, having been formerly included in the HVD
14 Lines and Substations Rehabilitation investment category. The other investment categories
15 in the HVD Lines Reliability sub-program are unchanged. This is illustrated in Figure 12
16 below.

FIGURE 12

CHANGES TO HVD LINES RELIABILITY INVESTMENT CATEGORIES SINCE CASE NO. U-21585

Investment Category	Change since Case No. U-21585
HVD Line Rebuilds	No Change
Pole Top Rehabilitation Miles	No Change
Individual Pole Top Rehabilitations	New to HVD Lines Reliability; formerly in HVD Lines and Substations Rehabilitation
Pole Replacements	Includes preexisting work in HVD Lines Reliability and work formerly in HVD Lines and Substations Rehabilitation
Switch Replacements	Includes preexisting work in HVD Lines Reliability and work formerly in HVD Lines and Substations Rehabilitation
Line Sensors	No Change
ROW Acquisition	No Change

1 **Q. How does the HVD Lines Reliability sub-program deliver on the intent of the**
2 **Reliability Roadmap?**

3 A. As discussed in the Reliability Roadmap, the Company's primary strategy for HVD lines is
4 to address HVD line components – poles, pole tops, conductors, and switches – with poor
5 asset health through a workplan that replaces those assets that have been identified as having
6 poor health. The Company focuses on lines with consistently poor reliability performance
7 and looks for the best remediation strategy to reduce risk and prevent future outages in the
8 most effective and economical way, generally using a least-cost, best-fit approach.

9 As described in the Reliability Roadmap, this sub-program specifically addresses
10 risks in the four major components of the HVD lines system: conductors, insulators, poles,
11 and switches. The Company identifies and assesses the health and risks related to these four
12 major components and mitigates that risk using a combination of line rebuilds, pole top
13 rehabilitation, switch and pole replacements to reduce the population of each asset at risk
14 and improve reliability performance. The HVD Lines Reliability sub-program is aligned

1 with the Reliability Roadmap because it executes the projects listed in Exhibit A-109
2 (MLH-3) and Exhibit A-110 (MLH-4) for specific HVD line rebuilds, pole top
3 rehabilitation projects, switch replacements and individual pole replacements needed to
4 continue to address the asset health risks on conductors, insulators, poles, and switches
5 identified in the Reliability Roadmap.

6 While the Reliability Roadmap primarily connects these HVD lines investments to
7 reducing asset health risk, these investments also play a key role in SAIDI performance, as
8 discussed by Company witness Kelly.

9 **HVD Line Rebuilds and Pole Top Rehabilitations Miles**

10 **Q. What kind of work is done in the HVD line rebuilds and pole top rehabilitation miles**
11 **investment categories?**

12 A. HVD line rebuilds consist of a complete overhead rebuild of a line or line segment,
13 including insulator, conductor, cross-arm, and pole replacements. Pole top rehabilitation
14 miles consist of replacing deteriorated cross-arms, insulators, cross-arm braces, and
15 hardware on pole tops without replacing the poles themselves, again along an entire line or
16 line segment. Lines in poor asset health that currently meet modern construction and design
17 standards, and that have standard conductors, will primarily receive pole top rehabilitation,
18 while lines in poor asset health that use non-standard and obsolete construction or equipment
19 will typically be rebuilt.

20 HVD line rebuilds take conductor, poles, and insulators in poor asset health off the
21 system as lines are rebuilt to current construction standards/configurations. Pole top
22 rehabilitation projects directly address lines with poor insulator health which is the leading
23 cause of line outage events over the past 5 years. See Company witness Kelly's testimony.

1 **Q. How does the Company determine which HVD line sections should be addressed with**
2 **line rebuild or rehabilitation projects in this sub-program, and how does it determine**
3 **whether to rebuild the line or only do rehabilitation?**

4 A. The Company utilizes past system performance and asset health data collected from
5 inspection programs to identify and prioritize projects that will optimize system
6 performance, reduce risk, and provide benefit to customers through improved reliability.
7 This data builds a model to prioritize HVD line segments based on actual outage history,
8 conductor type and configuration, health of insulators and poles, and the potential customer
9 impact if the line segment were to fail.

10 With few exceptions, lines that use non-standard and obsolete construction or
11 equipment are rebuilt to the modern standard with a new insulator, conductor, cross-arms,
12 structure replacements, tree clearing, and ROW procurement as needed. Lines that use
13 standard construction and conductor, have adequate pole health, but have poor insulator
14 health, are candidates for pole top rehabilitation instead of a complete rebuild.

15 **Q. Why does the Company rebuild lines that use non-standard and obsolete construction**
16 **or equipment?**

17 A. HVD lines with non-standard construction typically have higher outage rates due to their
18 outdated construction standards, such as unshielded conductors (which are more vulnerable
19 to lightning), small single-layer conductors, or copper conductors (both of which are less
20 durable than standard construction and require non-standard components to repair them
21 when they fail). Pole top rehabilitation does not mitigate these issues. Rebuilding a line to
22 modern standards improves durability and operational flexibility.

It is critical to remember that line rebuild projects and pole top rehabilitation projects both address lines that have already been identified as having outage problems. The question is simply whether the best way to address those problems is through a rebuild or rehabilitation.

Q. Please further explain the impact of asset health risk on project selection.

A. As shown in Figures 13 and 14 below, a substantial percentage of the Company's HVD lines insulators are at risk, with 35% falling into the vintage and victor, concerned and high-risk categories. Lines with high population of these insulators are considered to be in poor asset health and are prioritized accordingly. Similarly, conductor assets are also at some risk, with 14.4% of conductors classified as high risk based on their condition. Proposed line rebuild projects directly address the 14.4% of at-risk conductors by bringing those lines into the green portion of the donut chart. A major purpose of the Company's projected increase in HVD Lines Reliability investments is to address these risks.

FIGURE 13
HVD LINE INSULATOR HEALTH

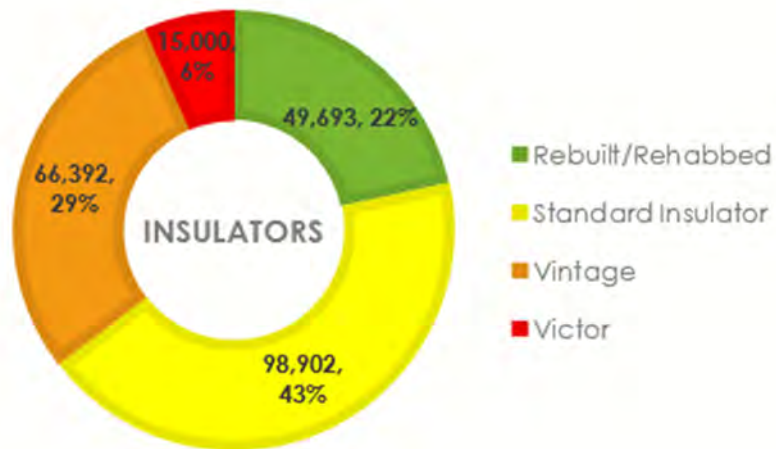
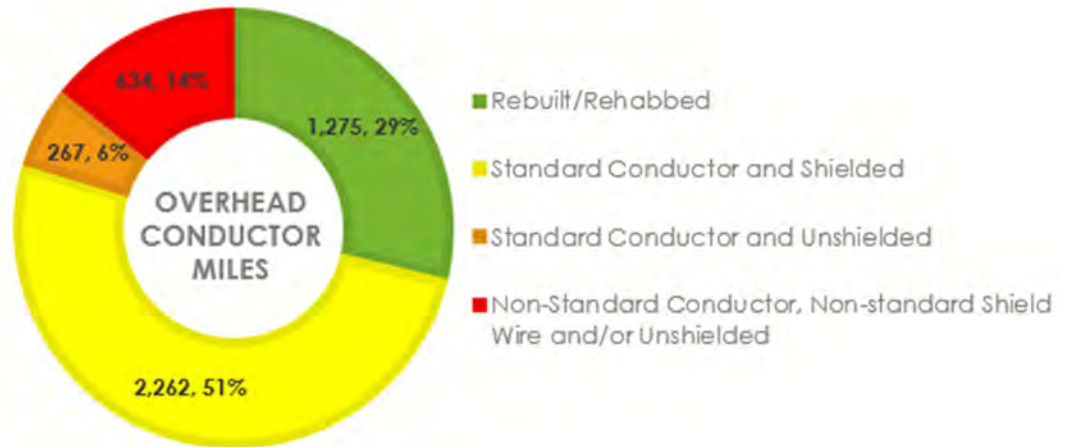


FIGURE 14
HVD LINE CONDUCTOR HEALTH

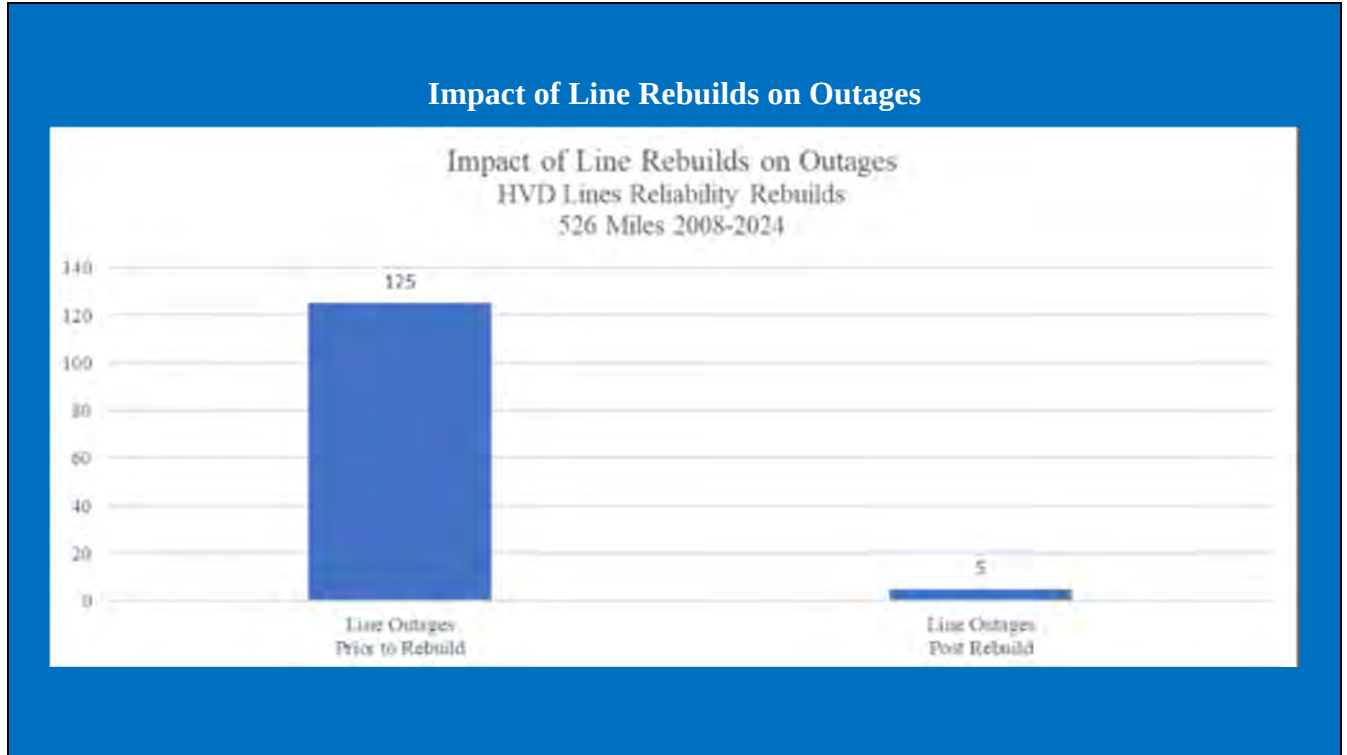


1 **Q. What specific benefits have HVD line rebuilds delivered for customers?**

2 A. Line rebuilds substantially improve the performance of a line, reducing or eliminating
3 outages and correspondingly reducing or eliminating interruptions to customers caused by
4 that line. Figure 10 below shows how, after completing a line rebuild, a line section
5 typically experiences minimal line equipment-related outages with a demonstrated 96%
6 reduction in outages.

7 In Figure 15, Prior Outages represent the number of line outages due to equipment
8 failure within the line section specified in the order number that occurred during the five
9 years before the rebuild Completion Date. Post Outages represent the number of line
10 outages due to equipment failure that have occurred since the Completion Date within the
11 rebuilt line section. Customers realize the benefit of fewer outages when the Company
12 rebuilds an HVD line section.

FIGURE 15



Individual Pole Top Replacements

Q. What work is done in the individual pole top replacements investment category?

A. The individual pole top replacements investment category does similar work to the pole top rehabilitation miles investment category, but instead of addressing entire lines or line segments, the individual pole top replacements investment category only replaces individual pole tops that represent an imminent failure risk. As noted above, individual pole top replacements were formerly accounted for in the HVD Lines and Substations Rehabilitation sub-program.

Q. How does the Company identify individual pole tops that are at imminent risk of failure?

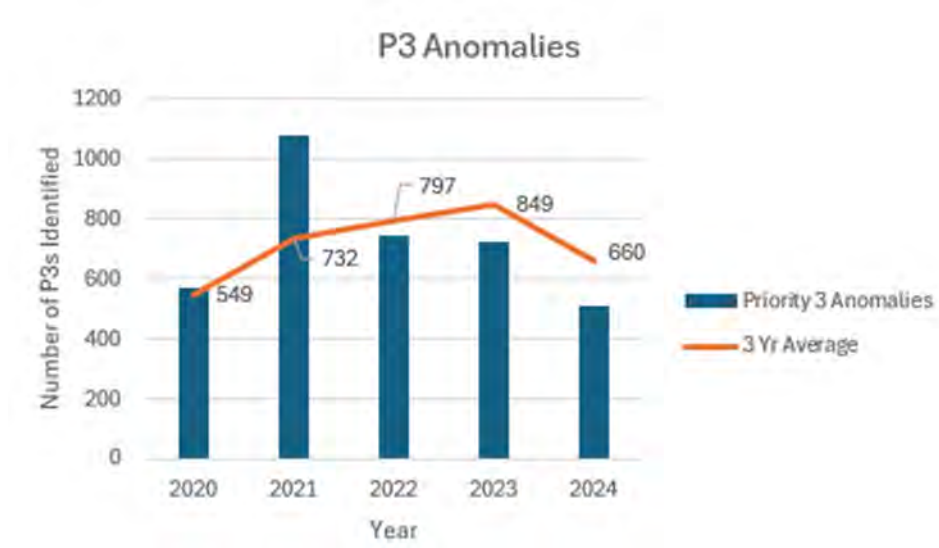
A. Individual pole top replacements are identified almost exclusively by helicopter and ground inspections. Pole top replacements identified as Priority 1 and some Priority 2 anomalies

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are replaced under the HVD Lines and Substations Demand Failures sub-program. The remaining Priority 3 anomalies represent imminent failure risk and fall into this sub-program.

During these inspections, the Company identifies anomalies visually using a camera that combines corona camera technology (for detecting cracked insulators using ultraviolet technology) with an infrared camera (to detect elevated thermal activity) during helicopter inspections to detect anomalies with high levels of accuracy. Although inspections have yielded fewer anomalies since 2021, as shown in Figure 16 below, the Company is still consistently identifying over 500 anomalies per year, with an average of almost 700 anomalies per year. This indicates that consistent investment in this category is needed to keep up with the deterioration of pole top assets such as cross arms and insulators. Failure to do so will result in worsening asset health risk on HVD lines, increased failures, and increased spending in the HVD Lines and Substations Demand Failures sub-program.

FIGURE 16



1 **Q. Can you provide further discussion on the Company's helicopter and ground**
2 **inspections?**

3 A. The Company performs aerial inspections of its HVD lines system via helicopter. As this
4 is a highly effective way to reduce HVD lines-related customer outages, the Company has
5 adjusted its helicopter inspection program to ensure flights happen earlier in the year and
6 more often to support the identification and correction of anomalies before they result in
7 outages.

8 The results of the helicopter inspection program are a significant source of
9 information to determine immediate action items. For example, a flight conducted with an
10 ultraviolet corona camera identified an insulator on one of the Company's 46 kV lines that
11 was emitting a corona signature (see Figure 17 below), prompting an immediate
12 replacement of the insulator to avoid an outage on the line, which would have interrupted
13 2,000 customers. The insulator in question was found to be cracked (which can result in
14 emission of corona) and was in imminent failure status. In this figure, the image on the top
15 left shows what the corona camera sees, with the red areas indicating that corona emissions
16 are detected. The image on the top right shows the same insulators upon closer visual
17 inspection, with the circle and arrow indicating where the insulator is cracked. The image
18 on the bottom shows a closer view of the same insulator.

FIGURE 17
UV ANOMALY IDENTIFIED WITH CORONA CAMERA



1 For safety reasons, helicopters do not fly over approximately 400 specific miles of
2 the HVD system. This is because it is difficult to land quickly and safely in the event of an
3 emergency within the areas of these miles. Most of these “no-fly lines” are in urban areas.
4 To inspect these lines, the Company performs a combination of driving, walking, or use of
5 drones to complete patrols of all 400 of these miles over the period of two years with a target
6 of 200 miles inspected per year. These inspections may include infrared and/or corona
7 inspection using handheld cameras.

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1 **Q. Can you provide visual examples of assets identified through these inspections?**

2 A. Figure 18 below is representative of common Priority 3 findings identified by helicopter
3 inspection. These assets are in advanced stages of deterioration and at increased likelihood
4 of failure. The arrows pointing to the cross arms indicate where they are cracked, splitting,
5 and starting to fail as the arm is no longer straight. Figure 18 shows how quickly these
6 assets can deteriorate once these reach a Priority 3 status. In Figure 19, the same structure
7 is photographed three months apart with the left side of the image being the first photo taken
8 and the right side of the image being the same structure three months later. These photos
9 indicate noticeable deterioration in the cross arm, as light is showing through the image on
10 the right but not in the original. When anomalies like the ones shown below are not
11 addressed through this sub-program, failures follow, causing interruptions to a large number
12 of customers and increasing spending in Demand Failures, where reactive work is more
13 expensive.

FIGURE 18
PRIORITY 3 CROSS ARM DETERIORATION EXAMPLES

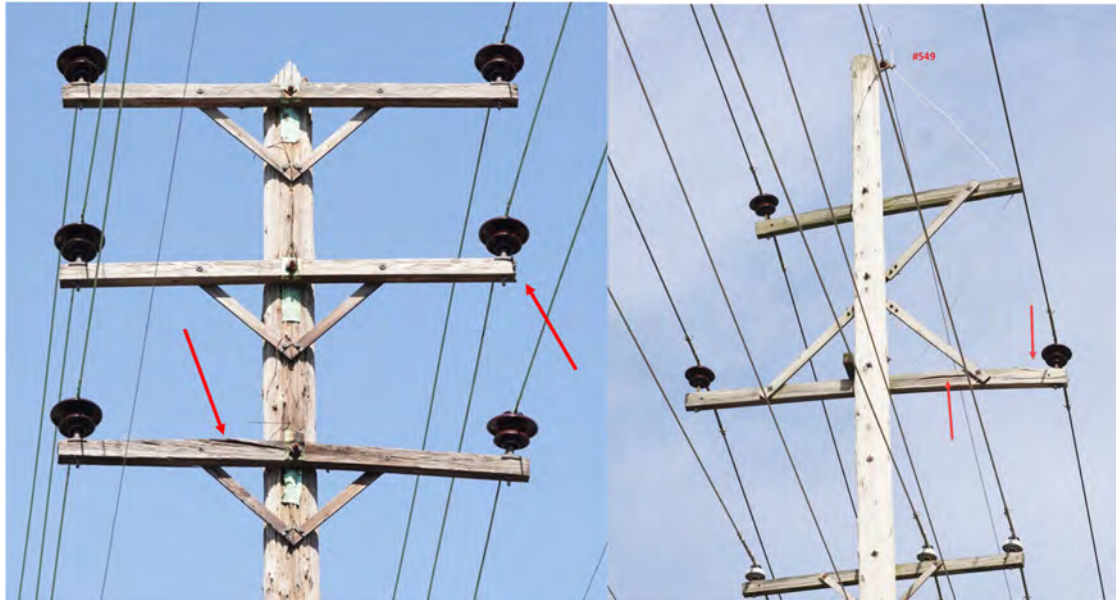


FIGURE 19
PRIORITY 3 CROSS ARM 3-MONTH DETERIORATION



In Figure 19, the left side is original, and the right side is three months later.

Pole Replacements

Q. What work is done in the pole replacements investment category?

A. Targeted pole replacements address poles identified during a previous annual pole inspection cycle that need to be replaced prior to the next inspection cycle.

Q. What is the Company's HVD pole inspection methodology and pole replacement criteria?

A. The Company's inspection and replacement criteria are provided in Exhibit A-107 (MLH-1) and are the same criteria the Company presented in other recent electric rate cases. The Company inspects HVD poles on an approximately 12-year cycle. A contractor performs visual inspections, sonic inspections, and bore testing on all poles 11 years old or older along specified line sections.

Q. How is this methodology and criteria used to identify poles in need of replacement as part of the pole replacement investment category in this sub-program?

A. HVD pole replacements in this sub-program are identified through the pole inspection program. Identified poles are grouped by line segment and reviewed to be included in a line rebuild project, line rehabilitation project, or individual pole replacement based on other line characteristics. For annual pole inspections, the Company identifies in advance which HVD lines will be inspected, so the Company knows which HVD lines will require pole replacements in the future based on inspection results. Given data about historical pole inspection failure rates, the Company can determine not only the HVD lines that will require replacements, but also how many poles on a given line are likely to require replacements. In 2025, the Company is planning to inspect 7,551 HVD poles across 160 different line sections as identified in Exhibit A-108 (MLH-2).

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1 **Q. Please further explain Exhibit A-108 (MLH-2).**

2 A. In Exhibit A-108 (MLH-2):

- 3 • Column (a) identifies HVD line names and column (b) identifies how many
4 poles will be inspected on that line;
- 5 • Column (c) identifies how many poles on each line the Company expects to be
6 rejected during inspection, based on historical rejection rates; and
- 7 • Column (d) identifies the cost associated for the replacement of rejected poles.

8 In Case No. U-21585 and other prior rate cases, the Company assumed that 80% of
9 its pole replacements would take place in this investment category in the HVD Lines
10 Reliability sub-program, while the other 20% would be classified as “rush” pole
11 replacement and be completed in the former HVD Lines and Substations Rehabilitation
12 sub-program. In the instant case, the Company is simply grouping all pole replacements in
13 the HVD Lines Reliability sub-program, although the Company will still prioritize some
14 poles over others for faster completion if warranted by inspection results.

15 Overall, the poles identified during this inspection process, along with poles
16 identified during previous inspections yet to be completed, will form the pole replacement
17 plan for the test year.

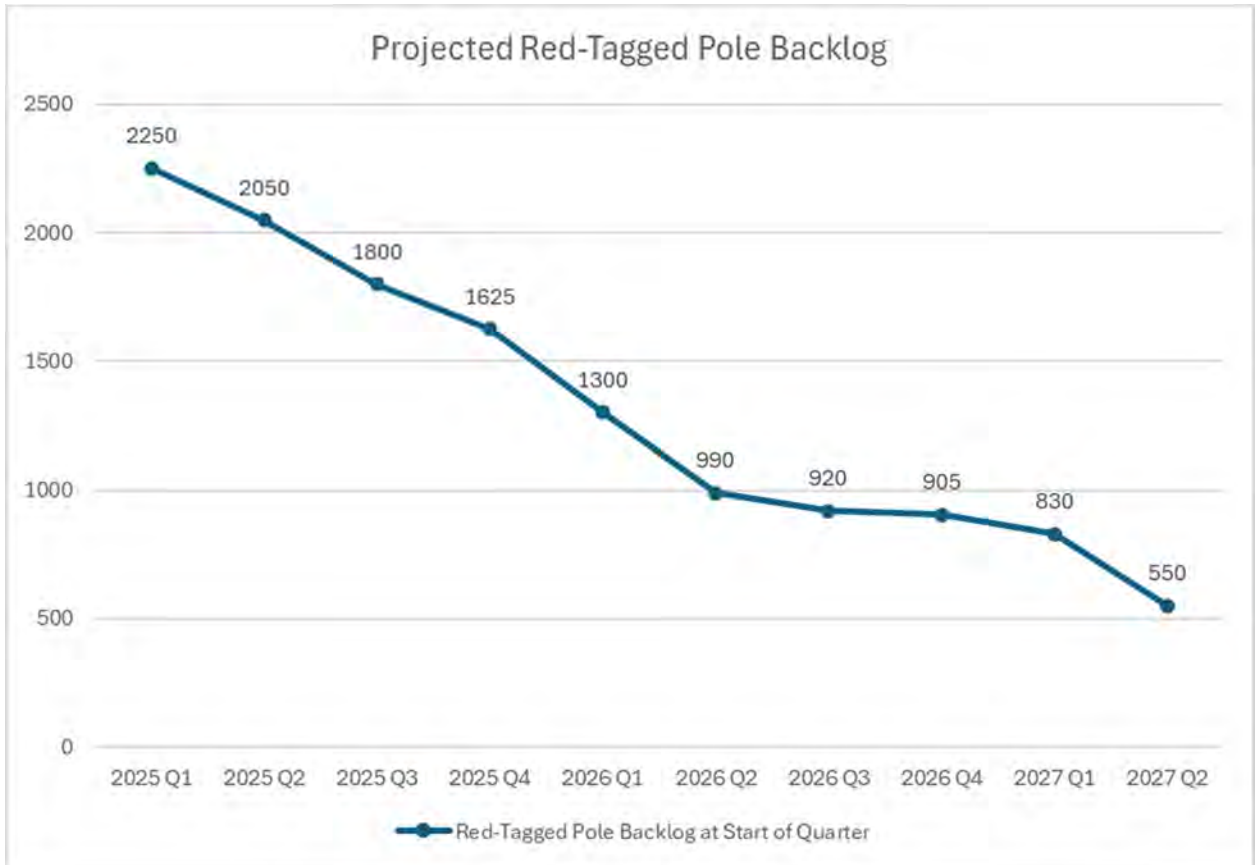
18 **Q. How many poles has the Company identified during previous inspection cycles and not**
19 **yet replaced?**

20 A. In the first quarter of 2025, the Company had a backlog of approximately 2,250 red-tagged
21 HVD poles that were identified in earlier inspection cycles but have not yet been replaced.
22 Those poles also inform the replacement plan for the bridge period and test year and will
23 supplement poles identified by ongoing inspections outlined in Exhibit A-108 (MLH-2).
24 The Company plans to clear this backlog through 2027, as shown in Figure 20 below. The
25 figure takes into account the projected pole replacements in this sub-program for the bridge

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and test year in addition to the projected number of poles expected to be rejected and added to the backlog from inspections during calendar years 2025 and 2026.

FIGURE 20
PROJECTED RED-TAGGED POLE BACKLOG



Q. Do pole inspections help identify projects for any other investment categories in this sub-program?

A. Yes. Switches are identified for replacement when the supporting pole is identified for replacement during the pole inspection program. As switch availability is critical for system operations, these locations are prioritized for replacement. Therefore, specific switch replacements in the test year will also be identified during 2025 pole inspections.

1 **Q. Are there other reasons to replace HVD switches?**

2 A. Yes. HVD switches, including Motor Operated Air Break Switches (“MOABS”), are
3 critical pieces of equipment that aid in the efficient isolation of faults, which can shorten or
4 mitigate outages for customers when a fault occurs. When these switches are inoperable, it
5 often results in more customers experiencing an outage and/or customers remaining without
6 service longer than if the switch had been available for operation. These switches are
7 identified for replacement through field operations feedback on operability concerns and
8 inspections. For example, MOABS are inspected regularly as their controls require power
9 to operate, and since they are called on to operate when the lines they are attached to lose
10 power, batteries provide power to the control of the MOABS to allow them to operate
11 appropriately. Periodic battery replacement ensures that power is always available to
12 operate the device. MOABS are tested annually to ensure the controls are in proper working
13 order and the batteries are replaced every three to four years, or sooner as needed.

14 In Case No. U-21585 and prior cases, the Company performed switch replacements
15 in both the HVD Lines Reliability and former HVD Lines and Substations Rehabilitation
16 sub-programs. In the instant case, the Company is now combining all switch replacement
17 work in HVD Lines Reliability.

18 **Line Sensors**

19 **Q. What kind of work is done in the Line Sensors investment category?**

20 A. The Company installs line sensors on HVD lines to provide increased visibility into
21 abnormal activity on the HVD system. Line sensors detect small variations in voltage and
22 current patterns, when and approximately where abnormal conditions are happening,
23 allowing the Company to investigate and take action before a possible failure occurs. In

1 addition, when a fault does occur, line sensors can help pinpoint the location of the failure
2 leading to quicker response, isolation, and restoration of service. Collected data aids in
3 project identification for other investment categories within the HVD Lines Reliability
4 sub-program. The Company continues to install line sensors with our switches to improve
5 isolation times reducing SAIDI and Customer Average Interruption Duration Index
6 (“CAIDI”).

7 **Q. Does the Company have line sensors installed anywhere else on the system? If so, what**
8 **benefit has been realized after installation?**

9 A. Yes, the Company has approximately 12,000 line sensors installed on the LVD system and
10 500 installed on the HVD system. As mentioned above, line sensors are being used to help
11 identify abnormal line conditions that alert the Company to a possible issue. As a result,
12 the Company has been able to investigate and correct these issues prior to them becoming
13 faults and interrupting service to customers. When faults do occur where line sensor data
14 is available, the data is being used to help locate the specific area of line that experienced
15 the fault and remotely isolate the fault or routing field personnel to those spots for quicker
16 response, isolation, and restoration of service.

17 **ROW Acquisition**

18 **Q. What is the purpose of ROW acquisition in this sub-program?**

19 A. The Company may need to acquire new rights of way, or expand existing ones, for a number
20 of reasons. New rights are often needed for relocation of existing lines during rebuild
21 projects. Expansion of existing rights is often required when the Company is rebuilding a
22 line in the existing corridor but cannot take the line out of service, and therefore needs a
23 wider ROW so the Company can continue providing service while building a new line

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1 adjacent to the existing one. Additional rights may also be required when rebuilding a line
2 to include larger conductor, requiring larger structures and larger structure supports.
3 Finally, additional rights may be required to bring existing easements to current standards,
4 allowing access for modern construction equipment and tree clearing standards.

5 **Q. How do you calculate the amount of ROW dollars needed for this sub-program?**

6 A. The Company projects that it will cost \$200,000 per mile for updating and expanding
7 existing land rights needed to support HVD line rebuilds and pole top rehabilitation projects,
8 based on the most recent actual ROW costs for an executed project. The Company is
9 projecting to spend \$12,667,000 in the bridge and \$11,000,000 in the test period to support
10 the acquisition of 63 miles and 55 miles of additional land rights, respectively.

11 **HVD Lines Reliability: Overall Investment and Benefits**

12 **Q. What is the Company's projected bridge period and test year spending levels, for**
13 **which it is requesting cost recovery, in the HVD Lines Reliability sub-program?**

14 A. The Company is projecting HVD Lines Reliability capital expenditures of \$133,667,000 in
15 the bridge period and \$107,667,000 in the test year. The Company is projecting unit and
16 capital expenditures in the bridge period and test year for each investment category as
17 identified in Figure 21 below.

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FIGURE 21
HVD LINES RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND PROJECTS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Benefit (customer minutes)	Test Year Capital	Test Year # of Units	Benefit (customer minutes)
Line rebuilds (miles)	\$38,614,000	13	329,517	\$35,743,000	65.8	1,371,211
Pole top rehabilitations (miles)	\$9,097,000	54.7	1,421,191	\$11,996,000	116.1	3,102,814
Pole replacements	\$54,856,000	2,010	2,572,172	\$33,569,000	1,230	1,574,016
Switches (incl. SCADA additions)	\$7,364,000	51	52,211	\$7,942,000	55	56,306
Pole Top Assembly Replacements	\$8,958,000	950	2,315,625	\$5,658,000	600	1,462,500
Line Sensors	\$2,111,000	168		\$1,759,000	140	
Right of Way Acquisition	\$12,667,000	N/A		\$11,000,000	N/A	
Total	\$133,667,000		6,690,716	\$107,667,000		7,566,847

Q. What are the customer minute benefits shown in that table above?

A. As explained earlier in my direct testimony, customer outage minutes is a mathematical product of the number of customers that would experience an extended outage of electrical service, and the duration in minutes of that outage, if a proposed project is not completed and the asset fails. A reliability project will lead to avoided future customer outage minutes by either reducing the probability of failure leading to an outage, the duration of the outage, and/or the number of customers impacted by the failure and subsequent outage. Calculations are based on assumptions for the number of impacted customers, outage

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duration, failure rate, and the amount of units impacted. Assumptions are based on historical actual failures versus asset population, average number of customers impacted by lines events, and traditional response duration. Figure 22 below provides these assumptions used in bridge and test period calculations for the HVD Lines Reliability sub-program.

FIGURE 22
HVD LINES RELIABILITY CUSTOMER OUTAGE MINUTES ASSUMPTIONS

Project Type	Assumed Customer Impact	Assumed Duration (minutes)	Assumed Failure Rate
Pole Replacements	3900	250	0.021
Switch Replacements	3900	250	0.021
Individual Pole Top Assembly ("PTA")	3900	250	0.04
HVD Other Projects	3900	250	0.021
HVD Line Rehabilitation per mile	Note 1	Note 2	0.02
Line Rebuilds Unshielded	Note 1	Note 2	0.032
Line Rebuilds Obsolete Conductor/ Shielded	Note 1	Note 2	0.022
Line Rebuilds Standard Conductor/Shielded	Note 1	Note 2	0.02

Note 1: Based on the customers fed from that specific line.

Note 2: Target restoration time based on system configuration. 125 Minutes for a looped line, 250 minutes for a radial line segment off a looped line, and 310 minutes for a complete radial line segment.

Q. What is the basis of the Company's requested spending level for the bridge period and test year in this sub-program?

A. The requested spending levels are based on the total of all costs in the Company's workplan. The costs for individual projects are developed based on information from actual project expenditures over the past five years that have been refined to take into consideration the project location, expected site conditions, project specific material needs, and any known

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1 anomalies in costs. The projected spending amounts for the bridge period and test year are
2 determined by the combined costs of individual, planned projects and will allow the
3 Company to complete the projects listed, and deliver the benefits defined, in Figure 11
4 above. The capital projects planned for the bridge period and the test year, as well as their
5 investment categories, locations, and benefits to reliability, are shown in Exhibits A-109
6 (MLH-3), page 1, and A-110 (MLH-4), page 1. Pole replacements will be identified based
7 on the process discussed above and reflected in Exhibit A-108 (MLH-2), with further
8 replacements in the test year also identified based on inspections done during 2025 and
9 2026. It is important to note that projects can span multiple years, so the dollar amounts
10 reflected in the exhibits are only the amounts that will be spent in the indicated time periods
11 and customer minute benefit is realized during the year of project completion.

12 **Q. Overall, what benefits will customers realize through the Company completing work**
13 **in the HVD Lines Reliability sub-program?**

14 A. As discussed in the executive summary of my direct testimony, customers realize improved
15 reliability and resiliency through the Company completing this work. Specific benefits of
16 the bridge period and test year planned projects are identified in terms of customer outage
17 minutes avoided. The customer outage minutes avoided for the bridge period and test year
18 HVD Lines Reliability projects are quantified in Exhibits A-109 (MLH-3), page 1, and
19 A-110 (MLH-4), page 1.

20 These investments also improve the asset health of critical HVD components that
21 would result in thousands of customer interruptions at a time when they fail. By improving
22 the HVD system, customers will experience fewer outages and have faster restoration when
23 outages do occur. HVD Lines Reliability investment is a component of the plan to achieve

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1 the Company's reliability outcomes as outlined in the Reliability Roadmap, as well as the
2 overall SAIDI improvements discussed by Company witness Kelly. Specific contributions
3 of the HVD Lines Reliability sub-program to SAIDI improvements are presented in the
4 direct testimony of Company witness Kelly.

5 While investment in HVD Lines continues to support a downward trend in overall
6 SAIDI impact, increased investment in this category will also provide a significant value in
7 proactive mitigation of deterioration and asset health risk, as discussed above and in the
8 Reliability Roadmap, and quickly fixing anomalies identified through inspections will
9 prevent significant interruptions to customers before they occur.

10 **Q. Does the Company consider any alternative approaches to the HVD Lines Reliability**
11 **projects?**

12 A. Yes, for each potential project the Company considers three options: line rebuild, pole top
13 rehabilitation, or addressing multiple individual system component degradation. As
14 described above, there are multiple factors that guide what approach is selected for each
15 given project.

16 **Q. What is the risk if the Company does not perform this work?**

17 A. An additional approach would be to not complete this work, which would result in the
18 degradation of assets, decreases in reliability, and an increase in threats to safety for
19 customers and Company workers. This would also impact system resiliency by affecting
20 how quickly customers can be restored. Customers would see an increase in outages as
21 system degradation would outpace system corrections. This is not prudent, as it would result
22 in more outages in service and increased costs to the customer in the long run as equipment
23 would have to be replaced on an unplanned basis.

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1 **Q. What has been the historical actual spending in the HVD Lines Reliability**
2 **sub-program for the past five years?**

3 A. The historical actual costs by investment category for HVD Lines Reliability are shown in
4 Exhibit A-113 (MPK-3), line 8. The Company's historical actual spending in the HVD
5 Lines Reliability sub-program for the past five years is also shown in Figure 23 below.

FIGURE 23
HVD LINES RELIABILITY HISTORIC EXPENDITURES

2020	2021	2022	2023	2024	5-Year Average
\$22,290,000	\$58,092,000	\$42,565,000	\$21,703,000	\$32,264,000	\$35,383,000

6 **Q. Please explain if the spending in any of the five historical years is a significant outlier.**

7 A. In 2021, spending was increased to align with the Company's workplan outlined in the 2021
8 EDIIP, and to the Company's overall level of investment approved by the Commission in
9 Case No. U-20697. Spending was reduced in 2023 to align with the Company's overall
10 approved level of investment in the settlement approved by the Commission in Case No.
11 U-21224.

12 **Q. How would these historical expenditures look if they included the work that was**
13 **previously done in the former HVD Lines and Substations Rehabilitation**
14 **sub-program?**

15 A. If one looked at the historical investments in HVD lines that were done in the former HVD
16 Lines and Rehabilitation sub-program, the totals would be those reflected in Figure 24
17 below.

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FIGURE 24
HVD LINES RELIABILITY HISTORICAL EXPENDITURES PLUS HISTORICAL REHABILITATION WORK

	2020	2021	2022	2023	2024	5-Year Average
HVD Lines Reliability Historical	\$22,290,000	\$58,092,000	\$42,565,000	\$21,703,000	\$32,264,000	\$35,383,000
HVD Lines Rehabilitation Historical	\$8,622,000	\$10,204,000	\$13,823,000	\$8,793,000	\$11,484,000	\$10,585,000
Total	\$30,912,000	\$68,296,000	\$56,388,000	\$30,496,000	\$43,748,000	\$45,968,000

1 **Q. What are the historical unit costs for each of the HVD Lines Reliability investment**
2 **categories?**

3 A. The historic unit costs for each category are provided in Figure 25 below:

FIGURE 25
HVD LINES RELIABILITY INVESTMENT CATEGORY UNIT COSTS

Investment Categories	2020	2021	2022	2023	2024	5-Year Average
Line rebuilds	\$358,800/ mile	\$1,029,600/ mile	\$455,500/ mile	\$1,675,300/ mile	\$741,800/ mile	\$717,700/ mile
Pole top rehabilitation miles	\$86,100/ mile	\$123,500/ Mile	\$75,700/ mile	\$72,100/ mile	\$113,700/ mile	\$100,300/ mile
Individual pole top replacements	\$8,100/PTA	\$10,300/PTA	\$9,900/PTA	\$8,400/PTA	\$10,200/ PTA	\$9,400/PTA
Pole replacements	\$20,600/ pole	\$24,200/Pole	\$27,800/pole	\$25,700/pole	\$33,200/ pole	\$26,800/ pole

4 **Q. Please explain any variation in unit costs over time.**

5 A. Individual projects can vary widely in cost from project to project based on specific project
6 conditions, and as a result, the year-end per-unit average cost can also vary. For example,
7 in Case No. U-20134, the Company considered 20 random work orders for pole
8 replacements, encompassing 240 total pole replacements, and found an average cost of
9 \$18,800 per pole for that sample. However, considering each of those 20 work orders
10 individually, unit costs ranged from \$10,300 per pole to \$29,300 per pole. Some of those

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1 work orders involved replacing poles in easier to reach locations than others or involved
2 working in differing weather conditions. Furthermore, HVD Lines Reliability projects often
3 extend from one year into the next, as the primary construction timeframe for these projects
4 is October through May. This construction timeframe is due to the peak loads seen during
5 the summer months, and the unavailability to take sections of the HVD system out of service
6 for replacement during those months. This timeframe also does not coincide with the
7 Company's fiscal year, causing variations in unit costs as money is spent in one year while
8 the units for the completed project are counted in the next year. In both 2021 and 2023, the
9 Company spent significant amounts for line rebuild projects that were not fully completed
10 until 2022 and 2024, respectively. Consequently, there is some spending shown in 2021 or
11 2023, while the project's units are counted in 2022 or 2024, affecting the apparent unit costs
12 for those years. This is also the case when comparing the bridge period and test year in
13 the instant case, as the bridge period includes work on multiple projects that will not be
14 completed until the test year.

15 **b) HVD Substations Reliability**

16 **Q. Please explain the HVD Substations Reliability sub-program.**

17 A. The HVD Substations Reliability sub-program ensures the long-term safe and reliable
18 operation of HVD substations, and ensures the ongoing asset health of HVD substations,
19 with spending to make needed replacements of existing substation equipment. HVD
20 Substations Reliability projects are identified and prioritized based on both asset health data
21 and inspection results, as discussed below.

1 **Q. Please provide a general overview of HVD substations and their purpose in the HVD**
2 **system.**

3 A. HVD substations take power from the Michigan Electric Transmission Company (“METC”)
4 138 kV system and drop the voltage to feed the Company’s 46 kV lines, that in turn feed
5 the Company’s LVD substations. HVD substations are designed with redundancy such that
6 the failure of a single component in an HVD substation will typically not result in outages
7 to customers. However, to facilitate repairs or construction, the HVD system is sometimes
8 temporarily configured in a manner that may remove a layer of redundancy; additionally, if
9 failures of multiple components in a substation occur in the same window of time, this could
10 result in customer outages. While rare, these outages can have a significant SAIDI impact
11 (two minutes of SAIDI or more, or greater than 1% of the Company’s recent annual
12 historical performance) when they do occur. In addition, there are many HVD substations
13 that are now well beyond their intended design life, increasing the probability of major
14 outages. To address these concerns, some HVD substations are being rebuilt under the
15 Transformer Bank Replacements and Substation Rebuilds sub-program, which is discussed
16 later in my direct testimony. Individual pieces or small groups of equipment that are of
17 concern are addressed here, under the HVD Substations Reliability sub-program.

18 **Q. What investment categories are included in the HVD Substations Reliability**
19 **sub-program?**

20 A. This sub-program consists of four investment categories:
21 a. circuit breaker and circuit switcher replacements;
22 b. transformer bushing replacements;
23 c. switch replacements; and

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- d. other targeted replacement programs for specific equipment, such as voltage transformer replacements and substation lightning arresters.

The replacement rationale for each investment category is included in Figure 26 below.

FIGURE 26
HVD SUBSTATIONS RELIABILITY REPLACEMENT RATIONALE

Replacement Category	Rationale for Replacement	Impact to Reliability
Circuit Breaker and Circuit Switcher	Obsolete Parts	Failure can cause a much larger number of customer outages if it occurs during a line fault.
Transformer Bushings	Higher failure rates than average bushing	Failure can cause customer outages if bushings fail. Bushing failures can also cause entire transformers to fail at significant cost.
Switches	Obsolete switches (replaced in conjunction with other substation work)	Failure can affect ability to remove equipment from service. Can significantly affect outage duration and repair costs.
Other Targeted Replacement	Safety hazard (potential to explode)	Failure can affect proper operation of substation. Failure can affect ability to power test equipment, lighting, etc.

Q. Has the Company made any changes to the work being done in the HVD Substations Reliability sub-program since Case No. U-21585?

A. As noted earlier in my direct testimony, some work that was included in the former HVD Lines and Substations Rehabilitation sub-program in Case No. U-21585 and prior cases has been transferred to the HVD Substations Reliability sub-program in the instant case. Specifically, the former HVD Lines and Substations Rehabilitation sub-program included projects to address issues with substation equipment identified during inspections. That work has been transferred to HVD Substations Reliability and inserted into the existing investment categories in this sub-program; no new investment categories have been defined.

Q. Please explain these substation inspections.

A. There are several inspection programs for substation equipment ranging from monthly patrol inspections, infrared inspections, to inspections of individual pieces of substation

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1 equipment. Similar to HVD lines inspections, these equipment inspections allow the
2 Company to be proactive in identifying equipment near failure and generating short cycle
3 planned work to replace an asset when that failure presents a risk to customer reliability
4 and/or system operability and are critical for monitoring and addressing asset health
5 concerns before the asset fails. Just as HVD lines inspections identify deteriorated
6 crossarms and other components before they fail, substation inspections provide advance
7 warning on a wide variety of substation assets in failing health.

8 After identification, the work is planned, prioritized, and executed to mitigate the
9 risk of unnecessary outages for customers or limitations to system operability. Lower
10 priority issues that must be addressed but are not at imminent risk of impacting customer
11 reliability or system operability, are planned for future years. When inspections identify
12 anomalies indicating a high likelihood of failure that would cause an impact to customer
13 reliability and/or system operability, the work is planned and executed to address the priority
14 item in a short cycle fashion. Examples of equipment that would fall into this portion of
15 this category include but are not limited to regulators, cap controllers, bushings, circuit
16 breakers, lightning arresters, and switches.

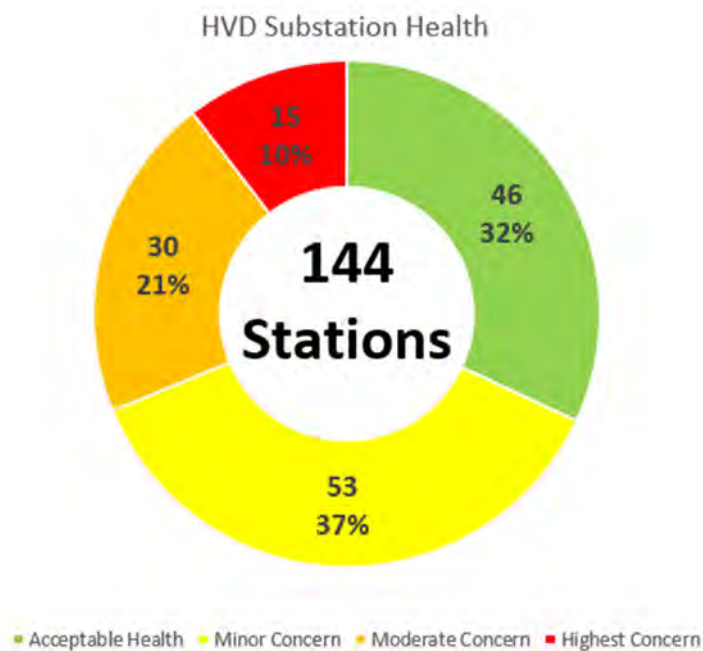
17 **Q. How is the HVD Substations Reliability sub-program delivering on the intent of the**
18 **Reliability Roadmap?**

19 **A.** As discussed in the Reliability Roadmap, the Company's primary strategy for HVD
20 substations is to address substation components – particularly circuit breakers, transformer
21 bushings, and switches – with poor asset health through a workplan that replaces those assets
22 that have been identified as having poor health, and/or assets that have been identified
23 through inspections, as discussed above. As the Reliability Roadmap notes, 10% of HVD

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substations are a high priority for repair or replacement and an additional 21% show cause for moderate concern, as shown in Figure 27 below. Compared to the Company's assessment of HVD substation asset health at the end of 2023, this figure shows fewer substations in the highest concern category, reflecting projects completed in the past year, but more substations in the moderate concern category. The increase in substations in the moderate concern category is indicative of deterioration progressing faster than the Company's rate of investment.

FIGURE 27

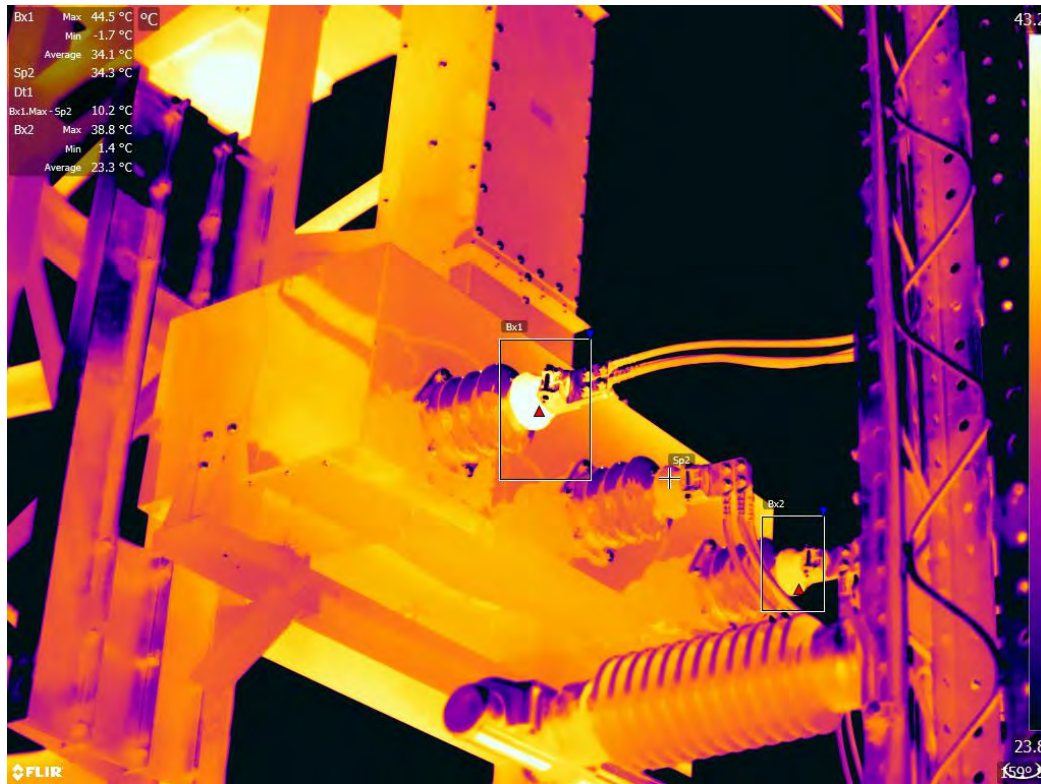


To address these risks, the Company established a plan in the Reliability Roadmap to increase investment in HVD substations. Much of the increased investment to address these risks will be performed in the HVD Lines and Substations Rehabilitation sub-program discussed later in my testimony, but increased investment in this sub-program will also address asset health issues in HVD substations.

1 **Q. How does the Company identify specific pieces of equipment with poor asset health**
2 **for replacement in the HVD Substations Reliability sub-program?**

3 A. To identify substation equipment that may need replacement, the Company uses an asset
4 health model that takes multiple inputs and analytic processes to aggregate numerous data
5 sources to best target assets in poor health that are likely to cause reliability issues in the
6 near term if they are not addressed. Based on the data in the asset health model, the timeline
7 for correction can range from 1-2 months, to prevent a near term failure, up to a planned
8 replacement coordinated with other work at the site in the following year. The inputs into
9 the health model come from the multiple inspections within the Company's substation
10 programs like infrared inspections, routine substation patrols, and diagnostic testing of
11 transformers and breaker oil and gases. The overall philosophy and methodology behind
12 the asset health model was discussed earlier in my direct testimony. Figure 28 below shows
13 an example of an infrared anomaly of an insulator identified during inspection, which the
14 Company would proactively address prior to a failure that would impact customers.

FIGURE 28



The model used to monitor the asset health of HVD substation assets is leveraged to identify specific areas to target investments based on likelihood, consequence, and severity of an asset's failure also known as that asset's risk. Projects are prioritized to deliver the greatest reliability improvements for the customer.

Q. What benefits will customers realize through completing the HVD Substations Reliability sub-program work, as proposed in this case?

A. The primary benefit of investing in HVD Substations Reliability at the levels proposed in the instant case is the improvement of asset health, which lets the Company prevent future potential high-impact outages that would result in significant customer interruptions and loss of system resiliency. As shown in Figure 27 above, 31% of HVD substations have either moderate or high concerns regarding asset health. While HVD substations are not a large overall contributor to systemwide SAIDI, HVD Substations Reliability investment

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does improve overall system reliability for the customer, resiliency in the HVD lines system, in addition to reducing asset health risk. The projected customer outage minutes avoided from HVD Substations Reliability investments are also discussed below and shown in Figure 29. Customer outage minutes saved are calculated based on assumptions for number of impacted customers, outage duration, failure rate, and the amount of units impacted. Assumptions are based on historical actual failures vs. asset population, average number of customers impacted by substation events, and historical response duration. The table below illustrates the assumptions used to calculate customer outage minutes avoided for HVD Substations Reliability.

Project Type	Assumed Customer Impact	Assumed Duration (minutes)	Assumed Failure Rate
Circuit Breakers	3900	240	0.00067
Bushings	3900	250	0.028
HVD Animal Mitigation	5850	120	0.067
Potential Transformer ("PT") Replacements	2000	240	0.01
Station Transformer Replacements	5850	240	0.005
Substation Rebuilds	11700	240	0.028

Q. Can you provide more detail on the circuit breaker and switcher replacement investment category?

A. Circuit breakers and circuit switchers are critical components of the HVD system, designed to minimize customer outage impact and mitigate equipment damage when the system

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1 experiences and clears an electrical fault. The replaced units are generally 1950s and 1960s
2 vintage oil or gas circuit breakers, given their poor performance, asset health, and the
3 increasingly limited availability of parts. In addition, there are some early models of circuit
4 switchers (notably certain S&C models) that have been deemed obsolete and have been
5 replaced under this program.

6 **Q. Can you provide more detail on the transformer bushing replacement investment**
7 **category?**

8 A. Transformer bushing replacements include bushing types with high failure rates, such as
9 Type U, and bushings with observed degradation as identified through testing and
10 inspection. Type U bushings have been known to lose dielectric strength due to a design
11 characteristic that can result in violent failure. This failure often results in oil spraying on
12 equipment, possible PCB contamination, and damage to the transformer and/or adjacent
13 equipment which can cause multiple minutes of SAIDI per event. The Type U bushings are
14 known industry-wide to have higher failure rates than average bushing failure rates. The
15 Company has been systematically replacing Type U bushings for several years, based on
16 customer impact and consideration of other scheduled work in the substation to maximize
17 workforce efficiency and utilization. The Company is also focusing on replacing Type O+C
18 bushings due to a known oil defect used in manufacturing. Some O+C bushing oil is
19 contaminated with corrosive sulfur that leads to degradation of the conductor and condenser
20 structure within the bushing. These can also fail violently resulting in the same concerns
21 noted above with the Type U bushings.

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1 **Q. How did the Company develop the projected expenditures for the bridge period and**
2 **test year in this sub-program?**

3 A. Spending is based on the projected number of projects in each substation reliability
4 category. Project costs were determined based on historical actual costs of comparable
5 projects of similar scope.

6 **Q. What is the Company's projected bridge period and test year spending levels, for**
7 **which it is requesting cost recovery, in the HVD Substations Reliability sub-program?**

8 A. The Company is projecting HVD Substations Reliability capital expenditures of
9 \$47,322,000 in the bridge period and \$39,680,000 in the test year as shown in Exhibit A-115
10 (MPK-5), line 4, columns (e) and (f). The Company is projecting unit and capital
11 expenditures in the test year for each investment category as identified in Figure 29 below.
12 Planned projects are listed in Exhibit A-109 (MLH-3), page 2, for the bridge period and in
13 Exhibit A-110 (MLH-4), page 2, for the test year.

FIGURE 29
HVD SUBSTATION RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Anticipated Customer Minute Savings	Test Year Capital	Test Year # of Units	Anticipated Customer Minute Savings
Circuit breaker/switcher replacements	\$20,038,000	63	39,312	\$23,737,000	74	46,176
Transformer bushing replacements	\$2,185,000	17	1,043,340	\$1,356,000	10	695,520
Switch replacements	\$2,822,000	46	941,850	\$1,829,000	34	696,150
Other	\$22,277,000	169	832,710	\$12,758,000	83	344,838
Total	\$47,322,000			\$39,680,000		

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Q. What has been the historical actual spending in the HVD Substations Reliability sub-program for the past five years?

A. The historical actual costs by investment category for the HVD Substations Reliability sub-program are shown below in Figure 30.

FIGURE 30
HVD SUBSTATIONS RELIABILITY HISTORIC EXPENDITURES

2020	2021	2022	2023	2024	5-Year Average
\$6,480,000	\$3,456,000	\$3,993,000	\$3,262,000	\$5,715,000	\$4,581,000

Q. How would these historical expenditures look if they accounted for work that was previously done in the former HVD Lines and Substations Rehabilitation sub-program?

A. If one looked at the historical investments in HVD lines that was done in the former HVD Lines and Rehabilitation sub-program, the totals would be those reflected in Figure 31 below.

FIGURE 31
HVD SUBSTATIONS RELIABILITY HISTORICAL EXPENDITURES PLUS HISTORICAL REHABILITATION WORK

	2020	2021	2022	2023	2024	5-Year Average
HVD Substations Reliability Historical	\$6,480,000	\$3,456,000	\$3,993,000	\$3,262,000	\$5,715,000	\$4,581,000
HVD Substations Rehabilitation Historical	\$5,045,000	\$5,211,000	\$4,712,000	\$4,826,000	\$4,403,000	\$4,839,000
Total	\$11,525,000	\$8,667,000	\$8,165,000	\$8,088,000	\$10,118,000	\$9,313,000

1 **Q. How do the projected bridge period and test year investment compare to historical**
2 **investment in this sub-program?**

3 A. As discussed above, the Reliability Roadmap defined a plan to increase investment in HVD
4 substation assets. The bridge period and test year in this case in this sub-program show
5 increases in alignment with the Reliability Roadmap.

6 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
7 **sub-program?**

8 A. No. Many projects in this sub-program often include additional requirements beyond just
9 the basic asset investment. This is common when system outages or reconfigurations are
10 needed to allow workers to perform work on these assets safely. As these outages and
11 reconfigurations are sometimes difficult to schedule, when they do take place additional
12 scope can be added to optimize the work that can be accomplished during a system
13 reconfiguration or scheduled outage. For example, switches are often replaced when work
14 is being done to replace a circuit breaker, as work conditions are ideal for addressing the
15 switches while the breaker is being replaced. The historic unit costs for each investment
16 category in the HVD Substations Reliability sub-program are included in Figure 32 below.

FIGURE 32
UNIT COSTS FOR HVD SUBSTATIONS RELIABILITY

Investment Categories	2020	2021	2022	2023	2024
Circuit breaker/switcher replacements	\$136,037	\$116,673	\$118,220	\$157,560	\$132,986
Transformer bushing replacements	\$78,571	\$107,997	\$105,017	N/A	\$136,738
Switch replacements	\$25,700	\$47,331	\$41,328	\$42,269	\$108,397
Other	\$36,471	\$5,698	\$51,840	\$16,642	\$40,293

1 **Q. Why do transformer bushing replacements not have a unit cost in 2023?**

2 A. In 2023, there were no bushing replacement projects completed in this sub-program. All
3 bushing replacements occurred on failed bushings or as part of projects in the former HVD
4 Lines and Substations Rehabilitation sub-program, and the Company did not break out these
5 unit costs in that sub-program.

6 **Q. Please explain any variation in unit costs year-over-year.**

7 A. Unit costs vary from year to year, as the apparent unit costs in this sub-program represent
8 total project costs, not necessarily the cost to replace a single unit of equipment. Projects in
9 this sub-program can vary greatly in scope, from a single piece of equipment being replaced
10 to multiple pieces depending on the health of the assets at the substation. This is especially
11 true for circuit breaker and circuit switcher projects, which require a significant amount of
12 clearance to perform the work. Because of this, the Company expects to replace more than
13 just individual breakers or switchers on the project. These projects will have expanded
14 scope to include bus work modifications, additional switch replacements, and adjacent
15 wiring to the control enclosures.

16 Additionally, the “Other” investment category has included a wide range of types of
17 projects over the years, making year-to-year cost comparisons difficult on a per-unit basis.

18 **c) Transformer Bank Replacements and Substation Rebuilds**

19 **Q. Please explain the Transformer Bank Replacements and Substation Rebuilds**
20 **sub-program.**

21 A. The Transformer Bank Replacements and Substation Rebuilds sub-program is dedicated to
22 1) the capital repair or replacement of HVD and SEC substation equipment (primarily large
23 substation transformers ranging in size from 2 MVA to 100 MVA), and 2) rebuilds of entire

1 substations. Both types of work typically consist of large projects that take place over
2 multiple years in stages, with costs incurred across multiple years before the project is
3 complete.

4 **Q. Why does the Company replace large substation transformers and rebuild HVD and**
5 **SEC substations?**

6 A. When the asset health of an entire substation or of a large transformer within a substation
7 deteriorates, the Company replaces them to reduce the risk of assets failing and causing
8 impacts to customer reliability. Replacing these assets proactively prevents long duration
9 outages that can often be 18-24 hours in length as the replacement of these assets often
10 requires the Company to use an emergency mobile substation set. A mobile substation
11 consists of substation equipment on a trailer that can be used to maintain service to an area
12 while work is being done inside a substation. In an emergency situation when a major
13 failure in a substation has occurred it can often take 18-24 hours to deliver and hook up a
14 mobile substation, which can lead to two or more SAIDI minutes per incident. As identified
15 in the Reliability Roadmap, many substation assets have outlived their initial intended
16 lifespan, with a significant percentage of HVD substations facing high or moderate asset
17 health concerns. While maintenance and inspection practices have, to date, allowed these
18 assets to perform beyond their normal end of life, substation rebuilds and transformer
19 replacements are needed to address these higher-risk assets.

20 **Q. Are these projects larger and longer-term than projects in the HVD Substations**
21 **Reliability sub-program?**

22 A. Yes. These are major investments and require multiple years to plan and secure equipment.
23 A transformer can take over two years to obtain after ordering and cost anywhere from

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1 \$1 million to \$5 million, depending on size and voltage rating. The multi-year nature of
2 these projects means that different project stages can take place in different years. For
3 example, one year may involve ROW procurement, another year may involve material
4 procurement, another year may involve construction, etc. The multi-year planning
5 component of these large projects makes it particularly important for the Company to have
6 predictably and consistently approved cost recovery on a year-to-year basis.

7 **Q. How does the Company determine if it will rebuild an entire substation or just replace**
8 **transformers within the substation?**

9 A. Multiple factors are taken into consideration when deciding to replace a transformer or
10 rebuild a substation. If a transformer bank and bushings are deteriorated, but the rest of the
11 substation is still in good operating health, then the Company will opt to replace the
12 deteriorated transformer. If multiple components of a substation are deteriorated, it
13 becomes more economical for the Company to rebuild the station instead of replacing a
14 large number of components individually. Figure 33 below shows an illustrative example
15 of the asset health model for HVD substations. In this example, *Sub A* would be a strong
16 candidate for a full rebuild, as the Company would need to address the transformers,
17 breakers, switches, and structure or concrete damage. Conversely, *Sub B* would be a likely
18 candidate for a transformer bank replacement, as the primary driver of the score for that
19 station is the failing health of the transformer bank itself.

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FIGURE 33
ILLUSTRATIVE SUBSTATION ASSET HEALTH MODEL

Category	Points per Occurance	Sub A	Sub B	Sub C
AC/FP/REC Wound	25	0	0	0
Age 50+	20	1	1	1
Oil or N2 Leaks	10	1	1	0
Transformer Internal Infrared	10	0	1	0
DGA Score	20	1	0	0
Brand A Bushing Issue	15	1	0	0
Brand B Bushing issue	5	0	0	0
IR P1/P2	20	0	1	0
Doble or Elec Test Issues	15	0	1	0
Transformer & Bushings Total		65	75	20
REG/LTC TOA R3/4	25	1		
IR P1/P2	20			
REG/LTC Total		25	0	0
OCB > 50 Yrs; GCB > 25 Yrs	5	7	3	1
3PH Reg/LTC Demand Order	10	1		
BRKR Oil or SF6 Gas Quality/Leaker	15		1	1
IR P1/P2	15			
Maint/RP Priority List	10			
Oil and Gas Circuit Breakers Total		45	30	20
99 & Cap Bank CSWs/VSW Issues	15	1		
SPT Watch List	10	2	1	1
Str & Concrete	5	1		
Other	5			
IR P1/P2	15		1	1
Ops Limiting Equip	20	1		
Station & Other Totals		60	25	25
Total Score Normalized		100	66.66667	33.33333
Gross Total		195	130	65

Q. How are investments in HVD substation transformer replacement projects aligned with the Reliability Roadmap?

A. The Reliability Roadmap states that the Company would need to replace an average of 12 transformers yearly between HVD and strategic customer substations to address transformers in poor asset health. Because these large transformers have a long lead time,

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1 the number of replacements actually completed in a given year may vary from year to year.
2 In the instant case, the Company is planning work related to 14 transformers in the bridge
3 period and three transformers in the test year.

4 Because it can take more than two years to obtain a single transformer, the Company
5 also places orders for transformers ahead of time to ensure they will be available in the years
6 beyond this current case to support the increased replacement levels described in the
7 Reliability Roadmap. The Company then makes “progress payments” on these transformer
8 orders to ensure their timely delivery from the manufacturer. As indicated in Exhibit A-109
9 (MLH-3), page 3, line 14, and Exhibit A-109 (MLH-3), page 3, line 9, the Company is
10 making progress payments in both the bridge period and test year. Making progress
11 payments will allow the Company to ensure it has a larger supply of transformers in the
12 future; the progress payments listed in my exhibits are for future deliveries of approximately
13 30 transformers.

14 **Q. Why is the Company working on more transformer replacements in the bridge period**
15 **than in the test year?**

16 A. As stated above, the Company needs to acquire production slots to ensure adequate delivery
17 of transformers, which is the purpose of the progress payments over the next few years.
18 Additionally, the relative numbers of projects in the bridge period compared to the test year
19 are related to resource availability in this sub-program as a whole. In the test year, the
20 Company is doing more work on the Alma and Blackstone substation rebuild projects,
21 which are discussed below. In the test year, these large projects will require more financial
22 investment and will also require more materials and more workforce than in the bridge
23 period (the substation rebuild projects themselves require multiple transformers). These

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factors mean the Company will not do as many transformer replacement projects in the test year.

Q. How are investments in HVD substation rebuilds aligned with the Reliability Roadmap?

A. The Reliability Roadmap states that the Company will complete approximately 2-4 HVD and strategic customer substation rebuilds per year. HVD substation rebuilds are generally very large projects that span two to three years, so in any given year the Company will likely be performing some work on more than two projects at once, and the Company may not always bring two projects a year to final completion. Also, as noted above, substation rebuilds themselves require new transformers, so the number of substation rebuilds can be inversely correlated with the number of transformer replacement projects. In the bridge period in this case, the Company is performing work on four different substation rebuild projects (see Exhibit A-109 (MLH-3), page 3):

- North Belding Substation: Costs in the bridge period represent labor and materials to complete this rebuild of this station which included replacement of a transformer and several breakers. Final checkout and asset in service is scheduled for mid-year 2025.
- Buskirk Creek Substation: This is a brand-new substation on a new parcel that will replace the Wayland Substation once it is complete. Scope of work in the bridge period will include the development of a new substation site, construction of substation support structure, and installation of equipment.
- Armory Substation: This is a brand-new substation on a new parcel that will replace the Alma Substation once it is complete. Scope of work will include transformer procurement costs of two units, property acquisition, environmental assessment, permitting expenses, land survey, and engineering costs.
- Royal Substation: This is a brand-new substation to replace the existing Blackstone substation on a new parcel. Scope of work will include transformer procurement costs for two units, property acquisition, environmental assessment, permitting expenses, and engineering costs.

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In the test year in this case, the Company is performing work on five different substation rebuild projects (see Exhibit A-110 (MLH-4), page 3):

- Buskirk Creek Substation: Costs in the test year represent completion of construction activities and final checkout before being put into service.
- Armory Substation: Scope to include continued transformer procurement and engineering costs. In addition, major materials like breakers, circuit switchers, capacitor banks, control enclosure, and structural steel will be procured.
- Royal Substation: Scope to include continued transformer procurement and engineering costs. In addition, major materials like breakers, circuit switchers, capacitor banks, control enclosure, and structural steel will be procured as well as land clearing/grading of the new site.
- Cement City Substation: Site preparation, which includes engineering and mobile pad work to support the rebuild of the Cement City Substation past the test period.
- Mecosta Substation: Site preparation, which includes engineering and mobile pad work to support the rebuild of the Mecosta Substation past the test period.

Q. Does the Company consider any alternative approaches to its substation investments in this investment category?

A. As discussed above, the first option is to address only the major asset or assets that are failing on an individual basis. If this can be done, it improves the overall health of the station with the minimum required scope and cost while addressing the risk in the most immediate timeframe. Full substation rebuilds are only done when there are multiple failing assets, which is then a more cost-effective option than replacing individual components. In the concept approval process, the Company reviews alternatives to address the main concerns at each site, and an alternative is selected that best addresses the main asset health concern while also minimizing impact to the grid and external stakeholders.

For the substation rebuild replacement projects, the projects were selected from a list of the 25 HVD bulk power substations evaluated as the highest priorities based on their

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1 asset health considering inputs from multiple groups within the Company. Adjustments to
2 the plan were then made based on geographic locations, other known large projects in
3 progress for the Company and METC, and the ability to schedule outages. Rather than
4 select from the list of possible substation locations for rebuilds, the other option would be
5 to attempt to run each HVD substation component to failure, but this would result in more
6 customer outages and increased costs to the customer in the long run as equipment would
7 have to be replaced on a demand basis. Transformer replacement projects were selected in
8 a similar manner, but prioritizing units with failing test data. Like the HVD substation
9 rebuilds, the other option would be to run these units to failure, which would result in
10 extended customer outages, due to the long lead time for manufacturing replacement units
11 (there are a limited number of spare HVD transformers in stock), and the small number of
12 mobile substations available for HVD voltages. When transformers fail prior to a scheduled
13 replacement, it creates a significant strain on completing other planned work, as often the
14 Company may have to reallocate a transformer meant for a replacement project to address
15 an actual failure. This delays the benefit of completing the planned projects and causes
16 cascading issues of rework for materials and resource allocation. At best, the result would
17 be higher costs to customers for the replacement of these units since the work would be
18 unplanned.

19 In the instant case, the Armory Substation (replacing Alma Substation) and Royal
20 Substation (replacing Blackstone Substation) replacement projects are among the
21 Company's 25 largest overall test year distribution projects, and the associated concept
22 approvals are included in the Company's Part III filing requirements, which show additional
23 details around how these projects were selected.

1 **Q. What is the Company's projected bridge period and test year spending level, for which**
2 **it is requesting cost recovery, in the Transformer Bank Replacements and Substation**
3 **Rebuilds sub-program?**

4 A. The Company is projecting Transformer Bank Replacements and Substation Rebuilds
5 capital expenditures of \$46,666,000 in the bridge period, and \$37,667,000 in the test year
6 as shown in Figure 34 below.

FIGURE 34
TRANSFORMER BANK REPLACEMENTS AND SUBSTATION REBUILDS INVESTMENT CATEGORY
EXPENDITURES

Investment Categories	Bridge Period Capital	Benefit (Customer Minutes)	Test Year Capital	Benefit (Customer Minutes)
Large Transformer Replacements	\$16,993,000	28,092	\$6,584,000	21,060
Progress Payments on Transformers	\$11,844,000	N/A	\$14,770,000	N/A
HVD Substation Rebuilds projects	\$17,829,000	157,248	\$15,313,000	78,624
ROW for New Substations	\$0	N/A	\$1,000,000	N/A
Total	\$46,666,000	185,340	\$37,667,000	99,684

7 **Q. Please list any projects that make up the requested spending level for the Transformer**
8 **Bank Replacements and Substation Rebuilds sub-program during the bridge period**
9 **and test year.**

10 A. Identified projects for this sub-program are listed in Exhibit A-109 (MLH-3), page 3, for
11 the bridge period and in Exhibit A-110 (MLH -4), page 3, for the test year. In Exhibit A-109
12 (MLH-3), page 3, lines 12 and 13 are two parts of the same project at the Delta College
13 Substation. In the test year, the Company is also planning to spend \$1,000,000 on ROW

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acquisition for new substations projects. The Company has experienced recent procurement challenges related to the Armory (Alma) and Royal (Blackstone) rebuild projects, indicating a need to have this step completed earlier in the project timeline as to not delay the replacement of these substations. Procurement of ROW for projects beyond the test period is necessary to keep these future multi-year projects on track.

Q. Please provide an overview of historical spending for the investment categories in this sub-program.

A. The historical actual spending, from when work was included in the former HVD Lines and Substations Rehabilitation sub-program, is shown in Figure 35 below. Note that this figure does not represent all historical spending in the former HVD Lines and Substations Rehabilitation sub-program, only the spending on transformer bank replacements and on HVD substations rebuilds.

FIGURE 35
TRANSFORMER BANK REPLACEMENTS AND SUBSTATION REBUILDS HISTORICAL SPENDING

Investment Categories	2020	2021	2022	2023	2024	5-Year Average
Large Transformer Replacements	\$1,522,399	\$3,598,057	\$4,682,117	\$6,240,187	\$2,934,464	\$3,795,445
HVD Substation Rebuilds	\$152,068	\$10,845,480	\$15,847,961	\$6,081,940	\$5,992,604	\$7,784,011

Q. How were the bridge period and test year spending amounts determined for the HVD substation replacement projects investment category?

A. For HVD substation rehabilitation work, spending for the bridge period is based on projects identified in Exhibit A-109 (MLH-3), page 3. Spending for the test year is based on projects identified in Exhibit A-110 (MLH-4), page 3.

1 **Q. How will customers benefit from investments in this sub-program?**

2 A. Benefits in this sub-program fall into a few categories. First, these investments will deliver
3 the customer minute benefits summarized in Figure 34 above. The projects address the
4 assets in the worst health at the Company's most critical substations. By replacing
5 transformers, and by replacing both transformers and other equipment when performing a
6 rebuild, the Company is ensuring that the substation is ready to serve the area for the next
7 50+ years.

8 **Q. What are the historical unit costs for this sub-program?**

9 A. Because this sub-program consists of a small number of large projects that often take place
10 over multiple years, there is not a meaningful way to calculate historical annual unit costs
11 for this sub-program.

12 **d) LVD Substations Reliability**

13 **Q. Please explain what projects, activities, and other types of work will be enabled by**
14 **expenditures in the LVD Substations Reliability sub-program.**

15 A. The LVD Substations Reliability sub-program ensures the long-term safe and reliable
16 operation of LVD substations, which are the interface point between the HVD lines and
17 LVD lines on the Company's system. The Company's LVD Substations Reliability
18 investments significantly reduce the risk of a customer experiencing a long duration outage.
19 While customers in more urban areas often can transfer to an adjacent substation through
20 LVD line switching in the event of a failure, for customers in more rural areas, there is no
21 ability to transfer substations. This increases the likelihood that an outage could be longer
22 in duration. To mitigate this risk, the LVD Substation Reliability sub-program has invested
23 in several categories, including:

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- (i) new or rebuilt substations;
- (ii) mobile substations;
- (iii) animal mitigation;
- (iv) substation transformer replacements; and
- (v) regulator replacements.

Q. Please explain why it is necessary to install new substations or rebuild existing substations to enhance LVD substation reliability.

A. New substations with new line circuits improve reliability by reducing the overall length of circuits. Shorter circuit miles reduce outage exposure, and new circuits allow for modified line protection schemes that can reduce the number of customers that experience outages during outage events. New substations provide additional capacity that can be used for planned and emergent customer transfers to minimize outage duration, and distribution automation schemes can be installed to transfer customers between substations during outage events. Before a new substation is considered, a study is completed to compare the SAIDI, System Average Interruption Frequency Index ("SAIFI"), and CAIDI benefits along with the economic costs of the new substation alternative to traditional line solutions, and to consider long-term system capacity needs to optimize new substation locations. A new substation may be installed if the system reliability improvements and economic benefits are comparable to or exceed traditional line solutions.

Substation rebuilds are necessary due to working clearance constraints within the compact designs of substation structures commonly constructed in the 1950s and 1960s. Operations and maintenance personnel are not able to operate or replace equipment without de-energizing the entire substation due to unacceptable working distances from energized

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1 components. This results in additional costs to use a mobile substation for planned projects
2 or increases restoration time and the number of customer outages needed for emergent work,
3 degrading the reliability of service provided to customers. Because of the new design and
4 expanded dimensions, modern electronic reclosers and regulators do not fit within these
5 compact structures without violating working clearances or electrical code clearances, i.e.
6 National Electric Safety Code (“NESC”) Rule 125, section A, titled “Working space about
7 electric equipment: Working Space (600 Volts or Less).”

8 **Q. What are mobile substations?**

9 A. Mobile substations are compact semi-trailer mounted substations that can be moved around
10 the state to restore interrupted service for long duration substation equipment repairs and
11 replacements or to maintain service to customers during planned substation projects.

12 **Q. Does installation of mobile substations improve reliability outcomes, including those**
13 **set forth in the Company’s longer-term distribution strategy?**

14 A. Yes. Mobile substations are used to maintain service to customers during planned
15 substation projects, for imminent failure concerns before interruptions occur, and to restore
16 interrupted service, limiting the negative reliability impacts.

17 **Q. What is the purpose of investment in animal mitigation measures?**

18 A. Animals that meet energized substation components cause service interruptions and
19 equipment damage. The purpose of each animal mitigation project is to keep animals, such
20 as squirrels and raccoons, out of the substation, and to insulate equipment to extend touch
21 potential if an animal gets into a substation, with specific measures chosen based on
22 substation characteristics. Common animal mitigation measures include:

- 23 (i) one-inch mesh fence (squirrels can squeeze through larger mesh);

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- (ii) concrete gate foundations (minimizes gaps and frost heave that create gaps over time);
- (iii) polycarbonate panels (three-foot panels installed at the top of the fence to mitigate animals from climbing over the fence);
- (iv) pole wraps and line discs (installed on poles and wires outside the substation to mitigate aerial access to the substation);
- (v) interior and exterior stone (eliminate gaps at the fence bottom to mitigate animals from crawling under the fence); and
- (vi) bushing guards on regulators and reclosers to extend touch potential to mitigate contact to energized components should an animal climb on equipment.

The Company also typically clears vegetation within 10 feet from the substation fence, except if a city or township requires vegetation to be closer for screening purposes or if the substation fence is within 10 feet of the property line, and the adjacent property has vegetation up to the property line. The Company's animal mitigation standards do not include measures to prevent bird intrusions because birds can fly over fences and barriers, but mitigation measures such as bushing guards can mitigate touch potential on energized components.

FIGURE 36
DAMAGE FROM ANIMAL CONTACT



1 **Q. How do the Company's proposed substation transformer replacement projects impact**
2 **customer reliability?**

3 A. Replacement of substation transformers that show evidence of degradation before failure
4 occurs prevents service interruptions.

5 **Q. How do the Company's proposed substation regulator replacement projects impact**
6 **customer reliability?**

7 A. Replacing substation voltage regulators that show evidence of degradation before failure
8 occurs prevents service interruptions, improves service quality, and prevents customer
9 equipment damage that can occur with unregulated service voltage.

10 **Q. Has the Company recently added any new types of investment to the LVD Substation**
11 **Reliability sub-program?**

12 A. Yes. Starting in 2024, three work items were moved to the LVD Substation Reliability
13 sub-program from other sub-programs:

14 (i) HVD line work associated with new and existing LVD substation projects;

15 (ii) ROW procurement; and

16 (iii) Distribution Supervisory Control and Data Acquisition ("DSCADA").

17 HVD line work and ROW procurement associated with new and existing LVD Substation
18 Reliability sub-program projects were previously part of HVD Lines and Substation
19 Capacity sub-program investments. To improve investment categorization and project cost
20 tracking, HVD line work and ROW procurement associated with LVD Substation
21 Reliability projects are now incorporated into the LVD Substation Reliability sub-program.
22 Projects to install DSCADA systems in existing LVD Substations were previously part of

1 the Grid Automation sub-program and are now an investment category within the LVD
2 Substation Reliability sub-program.

3 **Q. Does the Company have historical costs available for HVD line work associated with**
4 **new and existing LVD substations projects and ROW procurement?**

5 A. Prior to moving these two items to the LVD Substation Reliability sub-program in 2024,
6 the costs were not tracked separately, so historical costs are not available.

7 **Q. What is DSCADA?**

8 A. The Company has been installing DSCADA on its LVD substations for several years, and
9 now considers it a standard business practice, which is why it is no longer considered a Grid
10 Modernization effort and has been moved into this sub-program.

11 DSCADA is a foundational system that gathers real-time grid data and provides
12 substation device remote control capability. When DSCADA is installed at a substation, it
13 includes a Remote Terminal Unit ("RTU"), a local device that facilitates communications
14 with substation devices, and remote software systems. The communications component
15 uses a cellular modem to transmit more than 300 data points within the substation to the
16 Advanced Distribution Management System ("ADMS"). DSCADA investment includes
17 the required construction and installation of automation equipment at the substation, as well
18 as adding smart devices and controllers to core substation equipment.

19 **Q. How does the Company identify LVD Substations Reliability projects?**

20 A. The Company uses several inputs and analyses to determine how to best target LVD
21 Substations Reliability issues. These inputs help identify specific areas to target
22 investments based on probability of future issues and help to prioritize projects that will

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1 deliver the greatest reliability improvements based on SAIDI and SAIFI. These inputs
2 include:

- 3 • LVD circuit planners – Analyze historical outage trends on the LVD lines system
4 to identify areas of greatest reliability concern based on total number of outages,
5 trends in reliability performance, and potential reliability impact;
- 6 • Input from field operations and other departments – Inform substation planning
7 engineers on operational concerns and system constraints identified during
8 substation inspections, as described by Company witness Kelly, that may trigger
9 necessary projects, such as working clearance constraints;
- 10 • Animal intrusion data – Animal mitigation projects are implemented to mitigate
11 animal-caused substation outages;
- 12 • Equipment trend data – Planned replacement of substation equipment may be
13 triggered with trend data that indicates degrading equipment condition but has
14 not reached a concern of imminent failure; and
- 15 • Mobile substation planning – Includes assessing and maintaining the Company’s
16 mobile substation fleet based on historical project usage and the purchase of new
17 mobile substations to replace those which have become uneconomical to repair.

18 **Q. Does the Company consider non-wire alternatives in the LVD Substations Reliability**
19 **sub-program?**

20 A. Not presently. Non-wire alternatives are not mature enough to adequately address the
21 specific reliability issues that are the focus of this sub-program. As discussed by Company
22 witness Kelly, the Company is intending to undertake an expediated pilot process to better
23 understand how non-wire solutions (“NWS”) can be utilized for reliability.

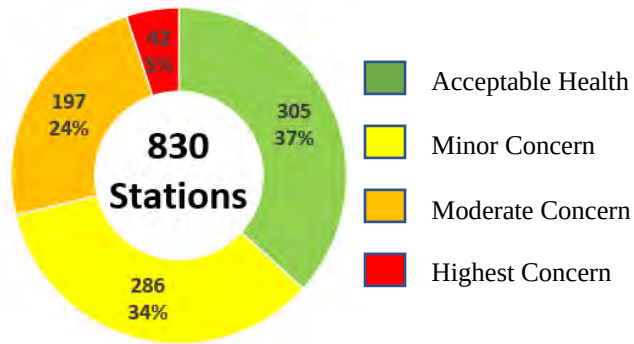
24 **Q. How are the projected LVD Substation Reliability expenditures aligned with the**
25 **Reliability Roadmap?**

26 A. Figure 37 below, taken from the Reliability Roadmap, shows that a majority of LVD
27 substations have at least some concerns in the Company’s assessment of their asset health.
28 Of the total population of LVD substations, 5% are a high priority for component repair or
29 replacement and another 24% have a moderate level of risk. As stated in the Reliability

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Roadmap, the Company plans to address these asset risks through a comprehensive plan to replace all components that are beyond end-of-life, including building and rebuilding substations, a plan which will result in two fewer LVD substation outages per year. Because LVD substation outages can impact a large number of customers, this will provide a meaningful reliability benefit. As shown in the Reliability Roadmap, this effort involves a ramp-up in LVD substation investment in both this sub-program and the LVD Substations Rehabilitation sub-program.

FIGURE 37
LVD SUBSTATION HEALTH



Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Substations Reliability sub-program?

A. The Company is projecting LVD Substations Reliability capital expenditures of \$48,504,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 9, column (k), and \$42,911,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 9, column (l). The Company's historical actual spending in the LVD Substations Reliability sub-program, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 9.

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Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as shown in Figure 38 below.

FIGURE 38
LVD SUBSTATION RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
New or rebuilt substations	\$28,200,000	17	\$18,990,000	12
Mobile substations	\$3,350,000	3	\$8,993,000	2
Animal mitigation	\$1,372,000	13	\$1,950,000	14
Regulator replacements	\$300,000	4	\$450,000	6
Transformer replacements	\$9,877,000	9	\$7,714,000	5
DSCADA Projects	\$5,405,000	15	\$4,814,000	11
Total	\$48,504,000	61	\$42,911,000	50

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Substations Reliability sub-program.

A. The Company has identified projects for the bridge period, listed in Exhibit A-109 (MLH-3), page 44, and for the test year, listed in Exhibit A-110 (MLH-4), page 4. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects. These exhibits also identify the location and benefits of the projects.

Q. Are there any projects that span multiple years?

A. Yes, the Angell, Buckeye, Edgewood, Harmon Road, Houghton Lake, Iargo, Lower Lake, Prescott, Pullman, Waldron, Westphalia, Mobile 26, Mobile 29, Belknap, Broadmoor TB3, Broadmoor TB4, Lagrave, Manton, and Walnut projects, listed for the bridge period in

Exhibit A-109 (MLH-3), page 4, and for the test year, listed in Exhibit A-110 (MLH-4), page 4, will span multiple years due to ROW acquisition, transformer purchase order milestone payments, mobile substation purchase order milestone payments, and construction scheduling.

Q. What benefits will customers realize through the Company completing work in the LVD Substations Reliability sub-program?

A. Customer benefits in this sub-program can be categorized as reducing customer-outage-minutes or as service quality. Replacement of equipment decreases the likelihood of failure, resulting in fewer minutes per year of outage on average. Since 2012, when the Company increased animal mitigation installations at LVD substations, approximately 92% of substations equipped with the present substation animal mitigation standard have experienced no animal-caused outages since the installation was complete.

As discussed above, DSCADA has been transferred to this sub-program, and the control and data-gathering capability of DSCADA lets the Company obtain grid data that is analyzed to make decisions on what field devices need adjustments to optimize performance. Expanding DSCADA broadens the customer base that can benefit from improved customer reliability and reduced outage durations. By adding substation communications, the benefits associated with volt-var optimization (“VVO”), conservation voltage reduction (“CVR”), distributed energy resource (“DER”) integration, automation transfer recloser (“ATR”) loops, and voltage regulator controllers will benefit more customers. DSCADA reliability benefits are driven by reduced outage response time and faster restoration via remote operations.

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Overall, the benefits for bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibit A-109 (MLH-3), page 4, and for the test year, listed in Exhibit A-110 (MLH-4), page 4. Types of benefits identified on the exhibits, and summarized in Figure 39, include:

- Customer-outage-minutes avoided – as defined previously, this is the expected reduction in the amount of outage time a group of customers would experience once the project is complete; and
- Service Quality – quantifies the number of customers benefiting from a project to improve the voltage to ensure that equipment operates properly as designed, keeping service point voltages within the ranges customers expect.

FIGURE 39
LVD SUBSTATIONS RELIABILITY BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	32,073,276	28,931,280
Service Quality; number of customers	2,471	2,825

Q. Are there customer reliability benefits from mobile substation purchases?

A. Yes. Mobile substations are purchased to support planned substation projects, planned lines projects, imminent failure concerns before customer outages occur, and unplanned failures to restore service to customers. Accordingly, it is difficult to predict where and when each mobile substation will be used to calculate the specific benefits.

Q. Please explain the historical year-over-year variation in spending in this sub-program.

A. In 2021, spending increased as the Company invested in 50 animal mitigation projects and seven transformer replacements. In 2022, the Company invested in four substation rebuilds, 31 animal mitigation projects, and three transformer replacements. In 2024, spending increased as the Company moved three work items to the LVD Substation Reliability sub-program from other sub-programs, as discussed above.

1 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
2 **sub-program?**

3 A. No. Average unit cost is not a good measure to predict the cost of an individual project in
4 the new or existing substation rebuilds, animal mitigation, and transformer replacement
5 investment categories due to specific work scopes needed for each project. New substation
6 costs can vary based on the substation design, electrical capacity required, site conditions,
7 etc. Substation rebuild costs can vary based on whether a full rebuild or a partial rebuild is
8 required and whether load transfers to an adjacent substation can be utilized or if a mobile
9 substation is required to maintain electrical service during the rebuild. Animal mitigation
10 costs can vary based on the substation physical size and whether full mitigation or partial
11 mitigation measures are required. Transformer replacement costs can vary based on the
12 electrical capacity and voltages of the replacement transformer and whether load transfers
13 to an adjacent substation can be utilized or if a mobile substation is required to maintain
14 electrical service during the replacement. The average unit cost does reflect the expected
15 spend per project for the regulator replacement investment category.

16 **e) LVD Substations Rehabilitation**

17 **Q. Please explain what projects, activities, and other types of work will be enabled by**
18 **expenditures in the LVD Substations Rehabilitation sub-program.**

19 A. The LVD Substations Rehabilitation sub-program includes capital repair or replacement of
20 LVD substation equipment that has not actually failed but has been assessed to be at
21 imminent risk of failure, projects to address code violations, and projects to replace obsolete
22 equipment. Obsolete equipment includes reclosers, breakers, fuses, regulators, lightning

1 arresters, and switches that can no longer be purchased from manufacturers, have depleting
2 inventory, and replacement parts can no longer be purchased.

3 **Q. What are the inputs used to determine what equipment may be in an imminent failure**
4 **status?**

5 A. Imminent failures are identified by monitoring and tracking LVD substation equipment and
6 components using various means of analysis such as dissolved gas analysis (“DGA”) and
7 infrared data. These analyses help to identify specific locations to target corrective action
8 based on probability of an unplanned event, and to prioritize projects that will deliver the
9 greatest reliability impact based on specific metrics (e.g. SAIDI and SAIFI). Proactively
10 replacing deteriorated equipment that is deemed as an imminent failure in advance of an
11 actual equipment failure is more economical as it typically avoids customer outages and
12 costly overtime. Some imminent failures are identified through monthly visual patrols
13 performed by the Company’s Substation Operations group and are replaced through this
14 program prior to failure. The cadence of the LVD substation equipment evaluation and
15 inspection is found in Figure 40.

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FIGURE 40
LVD SUBSTATION INSPECTION CADENCE

Inspection Task	Cadence	Actions Taken
All Station Components	Bi-Monthly	Visual inspection Routine patrol inspections
Entire Substation	Bi-Annually	Infrared inspection of entire substation
Protective Relays and Communication Systems	Dependent on relay model & failure history	Maintenance & testing performed
Station Batteries	Monthly	Voltage check
	Annually	Equalization
	Annually	Specific gravity reading
	4 Years*	Complete inspection
Power Transformers	Bi-Monthly	Visual inspection (including fans and pumps)
	Annually	Total combustible gas test (follow-up dissolved gas analysis tests, if warranted)
	Annually	Diagnostic Dissolved Gas Analysis of Load Tap Changer Oil (Transformers with Load Tap Changers Only)
	Annually	Diagnostic Dissolved Gas Analysis of mid-20 th century vintage Allis Chalmers Transformers
	Bi-Annually	Diagnostic Dissolved Gas Analysis of Transformer Main Tank Oil (Transformers with Load Tap Changers Only)
	6 years**	Diagnostic dissolved gas analysis of transformer oil (Non-Load Tap Changer Transformers)
Motor Operated Air Break Switches (MOABS)	Annually	Test Operated (decoupled)
	4 Years**	Battery replacement
Single Phase Regulators	9 Years***	Limited program of dissolved gas analysis
*Or periodically as needed		
**Or sooner if determined by combustible gas tests or high gas levels in previous tests		
***Started in 2014		

1 **Q. Do any other operating organizations or departments provide input into this**
2 **sub-program?**

3 A. Yes. Input from operating organizations and other departments inform the substation
4 planning engineers with operational concerns, system constraints, and regulatory changes
5 that may trigger a need for replacement of obsolete equipment, replacement of imminent
6 equipment failure, or substation modifications to comply with new regulatory requirements.

7 **Q. What investment categories are included in the LVD Substations Rehabilitation**
8 **sub-program?**

9 A. The LVD Substations Rehabilitation sub-program includes:

10 (i) Allis Chalmers substation transformer replacements, and

11 (ii) Equipment replacement and regulatory-related projects, which include end-of-
12 life condition substation rebuilds, equipment at risk of imminent failure,
13 addressing new regulatory requirements, and replacement of obsolete
14 equipment such as reclosers, breakers, fuses, regulators, lightning arresters,
15 and switches.

16 **Q. Please describe the Allis Chalmers substation transformer replacement investment**
17 **category.**

18 A. Allis Chalmers mid-20th century vintage substation power transformers were produced with
19 a design deficiency associated with the top clamping structure of the transformer windings.
20 The key purpose of the clamping structure is to prevent winding movement. This deficiency
21 results in an inherent weakness of the transformer to withstand the forces accompanying
22 certain magnitude low side faults. Winding movement typically results in electrical shorts
23 and arcing, which lead to excessive heating, creation of combustible gasses, and eventual
24 failure of the transformer.

Q. How many of these Allis Chalmers substation transformers are in-service at LVD substations and what has the Company's recent experience been with these transformers?

A. Going into 2025, the Company will have 31 of these Allis Chalmers units in-service in their original design, and another six rewound units in-service that are considered at risk of developing the condition, for a total of 37 units at its LVD substations. From 2014 through 2018, approximately 28% of the substation transformer failures had been from this vintage and manufacturer, but increased monitoring and replacement resulted in no transformer failures from this vintage and manufacturer from 2019 through 2024.

Q. What has been the Company's recent performance in replacing Allis Chalmers substation transformers?

A. The Company has been replacing Allis Chalmers transformers as follows:

	2017	2018	2019	2020	2021	2022	2023	2024
Allis Chalmers Transformer Replacements	9	10	15	6	19	7	5	3

Q. Please explain the equipment replacement and regulatory-related projects investment category.

A. When a substation is at the end of its useful life and experiences substantial deterioration – becoming unsafe, no longer able to reliably operate, or some other issue – the Company may elect to rebuild the substation. However, the Company is not planning any end-of-life condition substation rebuilds in the test year. For regulatory-related projects, the Company is planning projects related to working space, which bring substations into compliance with NESC Rule 125, section A, titled “Working space about electric equipment: Working Space (600 Volts or Less).” When the Company was working to upgrade its telecommunications

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1 at its LVD substations in the late 2010s, it discovered that some of the substations did not
2 meet the NESC working space requirements and began a process of addressing all of these
3 working space issues by 2028. The Company has completed 42 of the 66 identified capital
4 projects at its LVD substations and plans to complete the remaining 24 capital projects by
5 2028.

6 **Q. How does the Company treat obsolete equipment in this sub-program?**

7 A. When specific types of equipment can no longer be purchased from manufacturers,
8 replacement parts can no longer be purchased, and inventory levels are depleting, equipment
9 is classified by the Company as obsolete. Targeted replacements are implemented because
10 new equipment may not fit into the same location without structural substation
11 modifications due to physical size, mounting requirements, and electrical clearance
12 requirements.

13 **Q. Are there any projects that span multiple years?**

14 A. Yes, the Ballenger, Bellaire, Cooper, Crofton, Fountain, Gladwin, GMI, Godfrey, Golden,
15 Hart, Lennon Road, Lyons, Mayfair, Nestrom, Ottawa Beach, Saginaw Street, Stanton,
16 Dutton, Fairbanks, Howard City, Hudsonville, Lake Shore, Mancelona, New Richmond,
17 Nineteen Mile Rd, Port Calcite, and Steelcase projects, listed in Exhibits A-108 (MLH-2),
18 page 5, and A-110 (MLH-4), page 5, will span multiple years due to transformer purchase
19 order milestone payments and construction scheduling.

20 **Q. What benefits will customers realize through the Company completing work, in the**
21 **LVD Substations Rehabilitation sub-program?**

22 A. This sub-program works to address areas in LVD substations where code violations are
23 present, or where failures, and corresponding outages and customer interruptions, are

particularly likely. Addressing degrading equipment reduces the likelihood of failure, resulting in fewer minutes per year of outages on average. The benefits for the bridge period and test year projects are identified in the Benefit Type and Benefit columns of Exhibits A-108 (MLH-2), page 5, and A-110 (MLH-4), page 5. The types of benefits identified on the exhibits, and summarized in Figure 41, include:

FIGURE 41
LVD SUBSTATIONS REHABILITATION BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	52,145,000	38,240,000
Regulatory Compliance projects	13	6

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Substations Rehabilitation sub-program.

A. The Company has identified projects for the bridge period, listed in Exhibit A-109 (MLH-3), page 5, and for the test year, listed in Exhibit A-110 (MLH-4), page 5. These exhibits also identify the location and benefits of the projects.

Q. Are there circumstances in which Allis Chalmers substation transformer replacements could be reprioritized?

A. For several years occurring after the test year, the Company plans to replace the 20 remaining Allis Chalmers transformers at LVD substations. The Company prioritizes which transformers to replace each year based on DGA testing results and infrared data. While the Company has identified the projects for the bridge period and the test year, the Company could re-prioritize and target different transformers if testing results indicated that re-prioritization is warranted to reduce the probability of transformer failures across the system.

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1 **Q. Why is the Company requesting approval of these expenditures in this proceeding?**

2 A. The projects in the LVD Substations Rehabilitation sub-program replace degrading and
3 obsolete equipment with a high risk of causing service interruptions or reducing service
4 quality, resolve unsafe substation conditions, and resolve conditions that could degrade
5 substation reliability. Delaying replacement of this equipment is highly likely to lead to
6 unplanned outages, interrupting service to customers.

7 **Q. What are the Company's projected bridge period and test year spending levels, for**
8 **which it is requesting cost recovery, in the LVD Substations Rehabilitation**
9 **sub-program?**

10 A. The Company is projecting LVD Substations Rehabilitation capital expenditures of
11 \$40,895,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 16, column (k),
12 and \$31,147,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 16, column (l).
13 The Company's historical actual spending in the LVD Substations Rehabilitation
14 sub-program, along with the bridge period and test year projections, are shown in Exhibit
15 A-113 (MPK-3), line 16.

16 **Q. How did the Company develop its projected expenditures in this sub-program?**

17 A. The LVD Substations Rehabilitation sub-program is an important part of the Company's
18 plan to address deteriorating assets and maintain reliability. The bridge period and test year
19 spending amounts were determined based on the amount of investment needed to complete
20 the projects identified.

21 By investing at the projected spending level in the bridge period, the Company will
22 be able to: (i) complete 14 projects to replace Allis Chalmers substation transformers;
23 (ii) complete four projects to replace non-Allis Chalmers substation transformers;

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(iii) complete 16 purchase order milestone payments for transformer replacements beyond the bridge period; (iv) complete 13 projects to address working clearance code issues; and (v) complete five projects to replace equipment.

By investing at the projected spending level in the test year, the Company will be able to: (i) complete three projects to replace Allis Chalmers substation transformers; (ii) complete two projects to replace non-Allis Chalmers substation transformers; (iii) complete 15 purchase order milestone payments for transformer replacements beyond the test year; (iv) complete six projects to address working clearance code issues; and (v) complete four projects to replace equipment. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects. This level of spending is adequate to meet the sub-program goals and regulatory deadlines while remaining agile to address imminent failure concerns.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this sub-program will be allocated across the investment categories.

A. The Company is projecting units completed and capital expenditures in the bridge period and the test year for each investment category as shown in Figure 42 below.

FIGURE 42
LVD SUBSTATIONS REHABILITATION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Allis Chalmers substation transformer replacements	\$22,465,000	26	\$14,548,000	18
Equipment replacement and regulatory	\$18,430,000	26	\$16,599,000	13
Total	\$40,895,000	52	\$31,147,000	31

1 **Q. How are the projected LVD Substations Rehabilitation expenditures aligned with the**
2 **Reliability Roadmap?**

3 A. As previously discussed in the section of my testimony on the LVD Substations Reliability
4 sub-program, the Reliability Roadmap includes an assessment of LVD substation asset
5 health and presents an increased investment plan to address assets at risk. The Company is
6 increasing its investment in both LVD substations-related sub-programs in response to the
7 plan laid out in the Reliability Roadmap.

8 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
9 **sub-program?**

10 A. No, the average unit cost does not accurately reflect the expected spend due to specific work
11 scopes needed for each project and the variance in costs depending on the individual project
12 scope.

13 **f) Metro Reliability**

14 **Q. Please explain what projects, activities, and other types of work will be enabled by**
15 **expenditures in the Metro Reliability sub-program.**

16 A. The Metro Reliability sub-program ensures the long-term safe and reliable operation of the
17 Company's Metro systems with investments to install and upgrade the civil and electrical
18 assets that distribute electricity in those downtown cores. Metro Reliability investments fall
19 into three categories:

- 20 (i) obsolete or needed civil assets;
21 (ii) obsolete or needed electrical assets; and
22 (iii) dead fronting equipment.

1 **Q. How does the Company address projects that require modified civil infrastructure?**

2 A. For projects that require new or modified civil infrastructure, the Company releases the
3 scope to a contracted civil engineering firm, who creates a feasibility study for a civil
4 infrastructure path. The feasibility study provides several options for possible routes and
5 estimated construction costs for those options. The Company's metro engineering planner
6 reviews the feasibility study with operations representatives to determine ease of
7 construction and impact to future electric operations. The metro engineering planner
8 notifies the civil engineering firm, who will prepare a design based on the selected option.
9 The metro engineering planner will prepare an electrical design, cable pulling schedule, and
10 electrical bill of materials. The civil engineering firm delivers the design and any documents
11 needed to obtain a permit to perform work in the ROW from the Michigan Department of
12 Transportation or the municipality, including a detailed traffic control plan.

13 **Q. How are Metro Reliability expenditures aligned with the Reliability Roadmap?**

14 A. Planned Metro Reliability expenditures in this case are aligned with those presented in the
15 Reliability Roadmap, and projects are also identified based on the process outlined in the
16 Reliability Roadmap, whereby Metro planning and design engineers assess multiple
17 components of each vault, which produces a vault health score.

18 The Company reviews Metro Reliability projects during an annual planning cycle
19 each year. While the Company continuously monitors the reliability of the Metro system,
20 this annual review helps determine which line segments and components need to be
21 addressed each year, as some projects may be large enough to span multiple years.
22 Additionally, the Company determines which remediation strategy to use. Due to the
23 lengthy customer interruptions that a Metro outage can cause, these projects are proactive

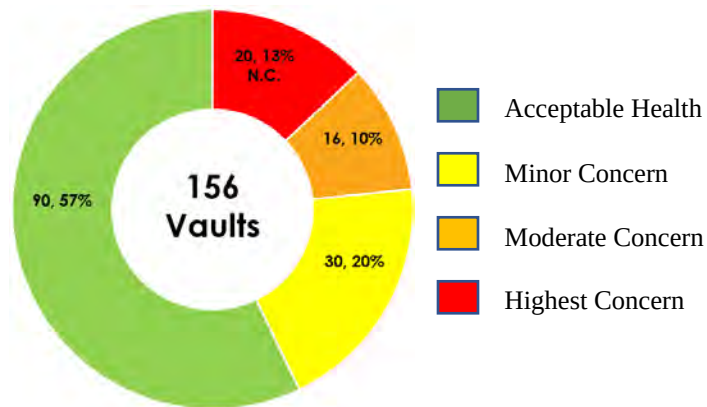
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to prevent an outage from occurring and not due to a previous interruption. Inputs the Company uses in its Metro reliability assessment include:

- Metro condition is assessed based on safety and ability to operate existing equipment;
- Projects are prioritized based on reliability benefits to each customer category, with highest priority for critical customers, followed by large residential customers and then other commercial and residential customers; and
- When the Company receives external requests, particularly for Metro New Business and Metro Asset Relocations, the Company may also perform Metro Reliability work at the same time to gain efficiencies.

The Company's current Metro asset health results are summarized in Figure 43 below.

FIGURE 43
SUMMARY OF METRO HEALTH VAULT ASSESSMENT RESULTS



Q. What types of work does the Company complete as part of obsolete electrical asset replacement projects?

A. The Company replaces functionally obsolete equipment, including:

- Deteriorated SF6 insulated switches with new SF6 insulated switches;
- Polychlorinated biphenyl ("PCB") oil-insulated voltage transformers with non-PCB transformers and dead front busing well inserts; and
- Impregnated Paper Lead Covered and Varnished Cambric Lead Covered cable with crosslinked tree retardant polymer insulated cables.

1 **Q. What types of work does the Company complete as part of dead fronting equipment?**

2 A. Dead fronting equipment enhances worker safety by eliminating exposed energized
3 components in Metro assets. The Company does this by replacing:

4 (i) Live-front, vault-style transformers and fusing with molded vacuum
5 interrupters;

6 (ii) Encapsulated transformer bushings (fuses and elbow type) and live secondary
7 buss with guarded load centers;

8 (iii) High rise live-front transformers; and

9 (iv) Padmount live-front transformers, including trans closures.

10 **Q. What benefits will customers realize through the Company completing work, in the**
11 **Metro Reliability sub-program?**

12 A. Metro Reliability investments minimize potential adverse impacts on customers by
13 improving overall reliability and operational safety. Civil projects share the benefits with
14 the corresponding electrical project. Benefits are fully realized when the electrical portion
15 is completed. Furthermore, investments in the Metro Reliability sub-program can reduce
16 overall cost associated with emergent response in the Metro Demand Failures sub-program.
17 Replacement of equipment decreases the likelihood of failure, resulting in fewer minutes
18 per year of outage on average. These benefits for the bridge period and test year projects
19 are identified in the Benefit Type and Benefit columns of Exhibits A-109 (MLH-3), page 6,
20 and A-110 (MLH-4), page 6. Types of benefits identified in the exhibits, and summarized
21 in Figure 44, include:

- 22 • Customer-outage-minutes avoided – as defined previously, this is the expected
23 reduction in the amount of outage time a group of customers would experience
24 in a year once the project is complete; and
- 25 • Worker Safety – create safer work conditions within metro vaults.

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FIGURE 44
METRO RELIABILITY BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	24,365	127,734
Worker Safety projects	2	2

1 **Q. What is an example of a recently completed Metro Reliability project that created**
2 **safer work conditions?**

3 A. The Company recently completed a vault dead fronting project at the JC Penney Vault in
4 Battle Creek. The vault previously had obsolete electrical equipment and presented a
5 worker safety concern to energized and exposed electrical components while working
6 within the vault. In addition, parts of the vault roof and walls required some concrete
7 rehabilitation repairs. The electrical equipment was updated to mitigate all exposed
8 electrical component hazards, and the civil repairs were completed and sealed with a
9 concrete sealant, extending the life of the structure.

FIGURE 45
VAULT BEFORE AND AFTER RELIABILITY PROJECT



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1 **Q. Are there customer reliability benefits expected from mobile vaults?**

2 A. Yes. The Company is planning to receive its two mobile vaults in 2025. Mobile Vaults
3 plan to be used as a tool to facilitate more dead-fronting equipment projects, and to decrease
4 the operational response time to unplanned vault transformer outages. These mobile vaults
5 will build on the Company's successful use of mobile substations and reduce costs through
6 the avoidance of custom, temporary above-grade installations or use of on-site generation.
7 Mobile vaults are proposed to support planned Metro projects and unplanned failures to
8 restore service to customers. Accordingly, it is difficult to predict where and when each
9 mobile vault will be used to calculate the specific benefits. What is known is that there is,
10 on average, \$12,800 O&M savings per vault per week based on the present cost of generator
11 rental, diesel fuel, and maintenance costs. The Company expects to realize approximately
12 \$400,000 in O&M savings per year based on anticipated usage.

13 **Q. Please describe the types of risks encountered as part of this sub-program.**

14 A. Risks that may be encountered during construction of Metro Reliability projects that can
15 impact cost include:

- 16 • Encountering crushed conduit while attempting to replace cable. Conduit can
17 be crushed as a result of heavy loaded objects above the ground or the fiberglass
18 becoming brittle as a result of exposure to soil conditions;
- 19 • Increased costs associated with temporary transformation and items required to
20 temporarily connect customers to this equipment. This is similar to the use of a
21 mobile substation to allow for safe maintenance or construction work on
22 de-energized equipment. However, instead of being on wheels, the set of
23 padmounted equipment must be temporarily constructed at grade level and
24 fenced to guard from the public; and
- 25 • Potential fluctuation in contractor costs. Contractor costs can fluctuate between
26 projects based on the bids received. This is based on the amount of work that
27 the contractor already has secured and the cost for the contractor to add this to
28 their work plan (additional or mobilizing resources).

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1 **Q. Please identify the projects that will be accomplished with the requested spending level**
2 **in the Metro Reliability sub-program.**

3 A. The Company has identified projects for the bridge period, which are listed in Exhibit A-109
4 (MLH-3), page 6, and for the test year, which are listed in Exhibit A-110 (MLH-4), page 6.
5 Projected project costs were determined based on the specific work scope for each project
6 and historical costs from similar projects. These exhibits also identify the location and
7 benefits of the projects.

8 **Q. Why is the Company requesting approval of these expenditures in this proceeding?**

9 A. The identified projects will benefit customers by addressing historical outages and ensuring
10 the long-term safe and reliable operation of the LVD metro system. These benefits will be
11 harvested through the replacement of degrading equipment before further service
12 interruptions occur, and by updating Metro vaults and manholes to modern design standards
13 and electrical clearances to improve worker safety.

14 **Q. What are the Company's projected bridge period and test year spending levels, for**
15 **which it is requesting cost recovery, in the Metro Reliability sub-program?**

16 A. The Company is projecting Metro Reliability capital expenditures of \$5,329,000 in the
17 bridge period, as shown in Exhibit A-113 (MPK-3), line 13, column (k), and \$3,998,000 in
18 the test year, as shown in Exhibit A-113 (MPK-3), line 13, column (l). These values are
19 consistent with the five-year average spend in this sub-program of \$4,811,000 as shown in
20 Exhibit A-113 (MPK-3), line 13, column (h). The Company's historical actual spending in
21 the Metro Reliability sub-program, along with the bridge period and test year projections,
22 are shown in Exhibit A-113 (MPK-3), line 13.

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1 **Q. How did the Company develop its projected expenditures in this sub-program?**

2 A. The bridge period and test year spending amounts were determined based on the amount of
3 investment needed to complete the projects identified. The Company has been experiencing
4 an increase in both incidents and customer-outage-minutes in the Metro systems in recent
5 years, as shown in Figure 46. By investing at the requested spending levels, the Company
6 has been able to repair or replace Metro assets that have been identified as contributing to
7 outages to downtown customers.

FIGURE 46
METRO SYSTEMS ANNUAL OUTAGE HISTORY

	2020	2021	2022	2023	2024
Number of incidents	23	26	17	26	31
Total customer-outage-minutes	457,422	550,414	341,144	344,979	903,757

8 **Q. Please explain how the capital expenditures projected for the bridge period and the**
9 **test year for this sub-program will be allocated across the three investment categories.**

10 A. The Company is projecting unit and capital expenditures in the bridge period and the test
11 year for each investment category as identified in Figure 47 below.

FIGURE 47
METRO RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Obsolete or Needed Civil Assets	\$1, 000,000	1	\$2,300,000	2
Obsolete or Needed Electrical Assets	\$704,000	2	\$1,098,000	3
Dead-Fronting Equipment	\$1,125,000	2	\$600,000	2
New Technologies (Mobile Vaults)	\$2,000,000	2		--
Total	\$5,329,000	7	\$3,998,000	7

1 **Q. Please explain the year-over-year variation in spending in this sub-program.**

2 A. Spending in this sub-program may vary from year to year, because the Metro systems have
3 a smaller number of projects than other Reliability sub-programs, and those Metro
4 Reliability projects can vary significantly in size and cost. In 2021, the Company completed
5 an above average amount of Metro Reliability projects, including a large project to replace
6 obsolete lead primary cables with polymer insulated primary cables in Grand Rapids, civil
7 infrastructure projects in Kalamazoo and Saginaw, and a vault dead fronting project in
8 Battle Creek.

9 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
10 **sub-program?**

11 A. No. Average unit cost is not a good measure of spend to predict the cost of an individual
12 project in this sub-program. There is a wide variance of scale and scope among the work
13 required ranging from \$250,000 to dead front a small vault to over \$1,000,000 for a civil
14 replacement project.

15 **g) Metro Rehabilitation**

16 **Q. Please explain what projects, activities, and other types of work will be enabled by**
17 **expenditures in the Metro Rehabilitation sub-program.**

18 A. The Metro Rehabilitation sub-program addresses assets on the Company's Metro systems
19 that have been identified as being at a high risk of imminent failure, such that replacement
20 is justified based on potential risks to public, employee, or contractor safety, or to maintain
21 the reliability of the Metro systems. The Metro Rehabilitation sub-program consists of two
22 investment categories: crushed duct replacements and vault or manhole rehabilitation.

1 **Q. Please explain crushed duct replacements.**

2 A. When an existing duct bank has been crushed or is deteriorated, it is replaced with a new
3 concrete-encased duct bank. New cable must also be run through the new duct bank to
4 replace the damaged cable.

5 **Q. Please explain vault or manhole rehabilitation.**

6 A. Vaults or manholes require replacement of the entire structure—or portions of the structure,
7 such as an existing roof—that is damaged or deteriorated. Damaged or deteriorated
8 subsurface structures create safety hazards to the public passing over them and employees
9 entering the structure.

10 **Q. How are the projected Metro Rehabilitation expenditures aligned with the Reliability**
11 **Roadmap?**

12 A. Similar to Metro Reliability, planned Metro Rehabilitation activities are tied to addressing
13 asset health concerns in Metro assets, and expenditures in this case are aligned with those
14 presented in the Reliability Roadmap. Projects are identified based on the process outlined
15 in the Reliability Roadmap as well.

16 **Q. Did the Company consider any alternative approaches to project selection that could**
17 **help achieve the Reliability Roadmap objectives?**

18 A. Yes. Alternatives are considered for each project in the Metro Rehabilitation sub-program;
19 however, viable options are often limited due to the need to maintain service in the dense
20 downtown districts. One alternative often evaluated is whether a given vault can be
21 eliminated and replaced with an at-grade transformer installation. This alternative is wholly
22 dependent upon suitable space to install the at-grade facilities, which often is not available
23 in the downtown areas. Alternative locations for the new facilities and rerouting of electrical

1 cables through already existing civil infrastructure are also considered. Each project is
2 selected based upon its effectiveness at solving the identified problem, the cost of the
3 project, and the relative benefits.

4 **Q. What benefits will customers realize through the Company completing work in the**
5 **Metro Rehabilitation sub-program?**

6 A. Upgrading and replacing degraded components in the Metro system allows the Company to
7 maintain a redundant system in the downtown areas of cities, providing a reliability benefit.
8 This benefit directly impacts customers including courthouses, jails, municipal offices,
9 police, and fire departments, as well as many businesses and residents. Replacement of
10 equipment decreases the likelihood of failure, resulting in fewer minutes per year of outage
11 on average. Additionally, a Metro system in good condition allows employees and
12 contractors to work in a safe environment and supports public safety. Investing in the Metro
13 system to alleviate failure conditions allows customers not to be single sourced as the
14 Company isolates manholes and vaults for repair. These benefits for bridge period and test
15 year projects are identified in the Benefit Type and Benefit columns of Exhibits A-109
16 (MLH-3), page 7, and A-110 (MLH-4), page 7. Civil projects share benefits with the
17 corresponding electrical project; benefits are fully realized when the electrical portion is
18 completed. Types of benefits identified on the exhibits and summarized in Figure 48 include
19 customer-outage-minutes avoided; as defined previously, this is the expected reduction in
20 the amount of outage time a group of customers would experience in a year once the project
21 is complete.

FIGURE 48
METRO REHABILITATION BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	77,680	153,550

1 **Q. Please identify the projects that will be accomplished with the requested spending level**
2 **in the Metro Rehabilitation sub-program.**

3 A. The Company has identified projects for the bridge period, listed in Exhibit A-109 (MLH-3),
4 page 7, and for the test year, listed in Exhibit A-110 (MLH-4), page 7. Projected project
5 costs were determined based on the specific work scope for each project and historical costs
6 from similar projects. These exhibits also identify the location and benefits of the projects.

7 **Q. Why is the Company requesting approval of these expenditures in this proceeding?**

8 A. The Metro Rehabilitation sub-program is a key component of the Company's plan to
9 improve overall reliability. This sub-program addresses those components of the Metro
10 asset base that are most vulnerable to failure and corresponding interruptions to customers.
11 By investing at the requested spending level, the Company will be able to repair or replace
12 Metro assets identified as being at a high risk of imminent failure.

13 **Q. What are the Company's projected bridge period and test year spending levels, for**
14 **which it is requesting cost recovery, in the Metro Rehabilitation sub-program?**

15 A. The Company is projecting Metro Rehabilitation capital expenditures of \$7,987,000 in the
16 bridge period, as shown in Exhibit A-113 (MPK-3), line 18, column (k), and \$5,993,000 in
17 the test year, as shown in Exhibit A-113 (MPK-3), line 18, column (l). The Company's
18 historical actual spending in the Metro Rehabilitation sub-program, along with the bridge
19 period and test year projections, are shown in Exhibit A-113 (MPK-3), line 18. This
20 sub-program was created in 2020; there was no spending in 2019.

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1 **Q. How did the Company develop its projected expenditures in this sub-program?**

2 A. The Company's projected bridge period and test year spending amount was determined
3 based on the amount of investment needed to complete the projects identified. The
4 Company is maintaining spending levels for the bridge period and test year to continue to
5 address rehabilitation projects.

6 **Q. Please explain how the capital expenditures projected for the bridge period and the**
7 **test year for this sub-program will be allocated across the two investment categories.**

8 A. The Company is projecting unit and capital expenditures in the bridge period and the test
9 year for each investment category as identified in Figure 49.

FIGURE 49
METRO REHABILITATION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Crushed duct replacements	\$1,300,000	2	\$4,993,000	2
Vault or manhole rehabilitation	\$6,687,000	8	\$1,000,000	2
Total	\$7, 987,000	9	\$5,993,000	4

10 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
11 **sub-program?**

12 A. No. Average unit cost is not a good measure of spending to predict the cost of an individual
13 project in this sub-program. There is a wide variance among work required, ranging from
14 \$200,000 for small vault projects to as high as \$1,850,000 for crushed duct and vault
15 rehabilitation projects.

h) System Protection

Q. What is the purpose of the HVD protective system?

A. The distribution system experiences electrical faults such as wire downs, lightning strikes, failed equipment, etc. When this happens, the purpose of a protective system is to de-energize as quickly as possible the minimum amount of the electric network that has experienced a fault, to isolate the fault, and mitigate damage to other equipment.

Q. Do protective systems experience failures?

A. Yes, protection systems have two modes of failure. The first is an *incorrect operation*, which is when a protective device operates when it should not. This failure mode can cause unnecessary customer outages, and in severe cases can lead to cascading outages that result in widespread blackouts. Protection system failures have played a part in many of the largest blackouts in history, including a protective system failure on November 9, 1965, that caused the “Northeast Blackout of 1965,” interrupting service to 30 million people; and a protective system failure on February 26, 2008, in Florida, resulting in 4,300 MW of generation going off-line, and a loss of 3,560 MW of customer load, and a fine to Florida Power and Light by the Federal Energy Regulatory Commission of \$25 million. Protection system failures also contributed to the largest United States blackout in history on August 14, 2003. These failures resulted in the creation of dozens of new reliability standards by the North American Electric Reliability Corporation related to the operation and maintenance of protective systems.

The second failure mode is when a protection system *does not correctly de-energize an electrical fault*. Failure of a protection system to de-energize a fault can lead to more customers interrupted than are necessary, equipment damage as lines and/or transformers

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1 burn up, environmental hazards due to ruptured transformers, and public safety hazards due
2 to fires, shrapnel from exploding equipment, and electric shocks due to uncleared electrical
3 faults.

4 **Q. Do failures detrimentally impact customers?**

5 A. Yes. Since failure of a protection system during a fault can result in extensive damage to
6 the electric network, it can take much longer to restore service to customers while additional
7 equipment is repaired or replaced. Due to these risks, protection systems are a critical
8 function of the electric network since they backstop against extensive outages and public
9 safety hazards when other components of the electric network fail. When protective systems
10 fail, this can result in the outage impacting a larger area than is necessary to isolate the fault.
11 This makes it more difficult to locate the problem on the electric network and extends the
12 time needed for restoration.

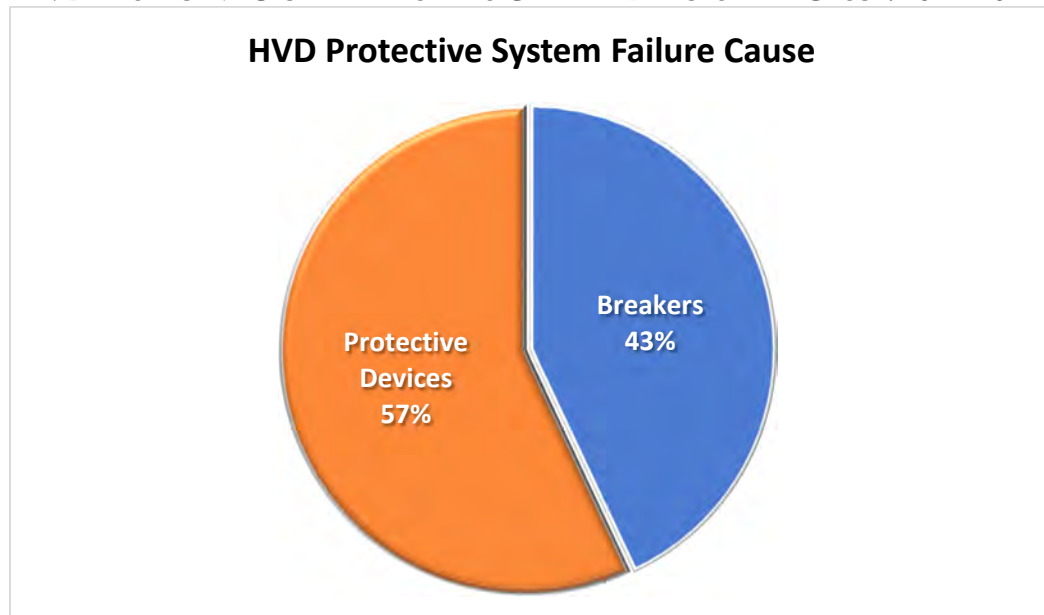
13 **Q. What is the present state of the Company's HVD protective system?**

14 A. The Company has determined design life for protective relays based on vendor
15 recommendations, industry best practices as documented by the Institute of Electrical and
16 Electronics Engineers ("IEEE") Power System Relaying Committee, and Company
17 experience with failure of specific relay types. Approximately 17% of the protective relay
18 population is older than the designated design life; this increases to 34% for the population
19 of electromechanical ("EM") relays. As EM relays age, they are more frequently out of
20 settings tolerance, which can cause interrupting devices (like circuit breakers, circuit
21 switchers, etc.) to open when they do not need to, or not open when they should, leading to
22 interruptions and possible damage to equipment. More frequent field testing and calibration
23 is required to assure proper performance.

1 **Q. How will replacing EM relays with digital relays support customer reliability?**

2 A. Digital relays do not lose setting tolerance like EM relays and require significantly less
3 maintenance. Historic EM relays require maintenance twice as often to keep within their
4 setting tolerance. Replacing historic EM relays with digital relays not only reduces the risk
5 of failure, but also lowers O&M expenses associated with relay testing. Over the past three
6 years, relays contributed to approximately 57% of the failures of an HVD protective system
7 to clear a fault and restore un-faulted HVD equipment correctly (see Figure 50).

FIGURE 50
HVD PROTECTIVE SYSTEM FAILURE TO CLEAR AND RESTORE BY CAUSE. 2022-2024



8 **Q. Why is the Company requesting approval for these projects in this proceeding?**

9 A. The relays replaced under this program are obsolete and, in most cases, no longer available,
10 so quick like-for-like replacement is not an option. Replacement requires building new
11 relay panels, which take several months to design, build, and install. Proactively replacing
12 these panels reduces the risk of several months of outages when a relay failure occurs.
13 Further, projections show an increasingly large number of obsolete relays reaching
14 end-of-life (with an increased risk of failing) over the next 10 years as described in the

1 Reliability Roadmap. A consistent level of investment to replace a smaller number of relays
2 each year will avoid a mass failure of relays in the future that would strain resources to
3 replace all at once.

4 **Q. What projects, activities, and other types of work will be funded by expenditures in**
5 **the System Protection sub-program, to help achieve these longer-term reliability**
6 **objectives?**

7 A. The System Protection sub-program replaces obsolete relays with new digital devices that
8 have fault monitoring capabilities to improve reliability and offset future O&M costs. This
9 sub-program targets relays that are reaching end of life.

10 **Q. What benefits will customers realize through the Company completing work in the**
11 **System Protection sub-program?**

12 A. As noted above and discussed in the Reliability Roadmap, protection systems are critical to
13 minimizing damage and protecting public safety as the final backstop when other
14 components of the electric network fail. Replacing end-of-life HVD relays before they fail
15 helps mitigate the expanded outage risk to customers and the hazard to the public. The
16 projected expenditures provide for the level of investments necessary in the System
17 Protection sub-program to address obsolete, poor performing relays to ensure proper
18 operability of the HVD network and minimize the risk of outages to customers.

19 **Q. Please provide additional information on the benefit to safety and how the investment**
20 **will benefit customers.**

21 A. If a protection system fails to de-energize a fault, it can result in safety hazards. For
22 example, a failed protection system can cause a conductor to remain energized on the
23 ground, posing an electrocution risk. A fault that is not cleared correctly by the protection

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1 system could also cause a fire, and/or an explosion of electric equipment like transformers.
2 An extended fault can also result in an environmental spill of oil. Investment in the HVD
3 protective system is paramount to ensuring the public is kept safe from the hazards of the
4 HVD electrical system.

5 **Q. How does the System Protection sub-program impact reliability?**

6 A. While safety is a key priority of the HVD protective system, the protective system also
7 directly impacts reliability. As noted above, there are two failure modes for protective
8 systems. When protective systems fail by operating when they should not, this can cause
9 unnecessary outages to customers due to tripping portions of the electric system that are not
10 experiencing a fault. When protective systems fail by not operating when they should, this
11 creates a need to interrupt more of the electric system than is necessary to clear the fault and
12 can interrupt more customers than necessary. The latter scenario can also cause additional
13 damage, such as transformer fires or damaging line conductors due to the extended fault
14 clearing times, and takes longer to repair and restore customers due to the additional damage
15 and larger area of outage.

16 The System Protection sub-program also plays a role in reducing the CAIDI, which
17 in turn reduces SAIDI. New digital relays contain oscillographic recording functions that
18 allow for evaluation of system conditions in real time, allowing engineers to remotely
19 interrogate the system to locate faults more quickly and with more precision. This allows
20 repair crews to find the problem and address it more quickly, restoring customers faster,
21 which reduces CAIDI.

1 **Q. Are there any other benefits to replacing EM relays with digital ones?**

2 A. Experience has shown that digital relays can be tested once every five years instead of once
3 every four years for EM relays. The time spent to test and calibrate digital relays is 50%
4 less than a comparable EM relay. One HVD relay project typically replaces six EM relays
5 with two new digital relays. Considering these reductions, the Company estimates that a
6 modern digital relay package requires 87% less O&M expense on average to maintain than
7 a comparable EM unit.

8 **Q. What is the Company's projected bridge period and test year spending level, for which**
9 **it is requesting cost recovery, in the System Protection sub-program?**

10 A. The Company is projecting System Protection capital expenditures of \$6,768,000 in the
11 bridge period and \$4,098,000 in the test year, as shown in Figure 51 below.

FIGURE 51
SYSTEM PROTECTION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Category	Bridge Period Capital	Bridge Period Units	Test Year Capital	Test Year Units	Benefit
Relay Replacements	\$6,768,000	61	\$4,098,000	24	Safety, Reliability
Total	\$6,768,000	61	\$4,098,000	24	

12 **Q. What is the basis for the Company's projected test year spending level in the System**
13 **Protection sub-program?**

14 A. The Company's projected System Protection investment in the test year closely aligned with
15 the five-year average, which is shown in Exhibit A-113 (MPK-3), line 11. Based on the
16 relay asset health model, spending at the five-year average level will reduce the quantity of
17 installed relays beyond their design life to zero in seven years and sustain that level going
18 forward from that point.

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This level of investment will support 24 relay units at six sites in the test year. The specific costs for the test year projects were determined using unit costs based on past work order costs for replacement of like equipment, and further refined taking into consideration the complexity of the specific relay schemes as well as the need for replacement of control enclosures due to NESC working space requirements. The average unit costs for the test year are expected to be higher due to one project requiring a new control enclosure due to NESC working space requirements, and elevated costs to remediate asbestos relay panels at three sites.

Q. Please list any projects that make up the requested spending level in the System Protection sub-program for the bridge period and test year.

A. Projects for the System Protection sub-program are identified in Exhibit A-109 (MLH-3), page 8, and Exhibit A-110 (MLH-4), page 8.

Q. What has been the historical actual spending in the System Protection sub-program for the past five years?

A. The historical actual costs for the System Protection sub-program are shown in Figure 52 below.

FIGURE 52
SYSTEM PROTECTION HISTORIC SPENDING

2020	2021	2022	2023	2024	5-Year Average
\$2,626,241	\$2,620,111	\$4,504,000	\$4,386,998	\$4,848,000	\$3,797,000

Q. Please explain the year-over-year variation in spending in this sub-program.

A. In 2020 and 2021, the effects of the pandemic resulted in a decrease in the overall spending in this sub-program compared to earlier years as availability of construction resources and materials was challenged, so spending increased after that point to return to more normal

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levels. Additionally, beyond 2021, spending has ramped up to mitigate the risk described above of relays in service beyond their design life as identified in the relay asset health model.

Q. What are the historical unit costs for the System Protection sub-program?

A. Historical unit costs are provided in Figure 53 below; note that some projects span multiple years:

FIGURE 53
SYSTEM PROTECTION UNIT COSTS

Investment Categories	2020	2021	2022	2023	2024
Locations	6	3	10	10	6
Total Relay Replacements	58	13	41	36	17
Cost per Location	\$437,707	\$873,366	\$409,455	\$409,455	\$808,000
Cost per Relay Replacement	\$45,280	\$201,546	\$109,854	\$121,861	\$285,176
5-Year Average Cost per Relay Replacement	\$115,061				

Q. Please explain any variation in unit costs over time.

A. Costs per location can easily vary because each project at each given location can involve a different number of relay replacements. Additionally, some projects carry over from one year to the next; in these cases, dollars are spent throughout the project, but the unit is only counted once it is complete. This makes unit costs less consistent from year to year. For instance, the 2021 unit cost was relatively high because several units that began in 2021 did not complete until 2022, while most of the cost of those projects were incurred in 2021. The 2020 unit cost was relatively low because of the high unit count of projects carried over from 2019, where most of the costs for those projects were incurred in 2019. Similarly, the

2024 unit cost was high because many units started in 2024 will be completed and counted in 2025. Averaging the unit cost over the life of each project rather than by budget year brings a more consistent unit cost average of approximately \$115,000 per relay replacement.

2. CAPACITY

a) HVD Lines and Substations Capacity

Q. What is the purpose of the HVD Lines and Substations Capacity sub-program?

A. The overall purpose of the Capacity Program is to ensure that the system can serve peak demand load, as discussed by Company witness Kelly in his direct testimony. The HVD Lines and Substations Capacity sub-program is specifically designed to:

- Ensure capacity needs on the HVD system in accordance with HVD planning criteria;
- Accommodate new interconnections to the HVD System;
- Improve functionality through standards, upgrades to protection, and operability of the system;
- Coordinate with transmission infrastructure additions; and
- Support ROW acquisition projects to support HVD Lines and HVD Substation projects in this sub-program as well as ROW acquisition needed to bring existing HVD Line and HVD Substation ROWs up to present standards.

Q. To what extent are HVD Lines and Substations Capacity sub-program investments “planned”?

A. Each Capacity sub-program consists primarily of investments that are proactive, in that they do not respond to an emergency. However, there are circumstances where projects may need to be pulled ahead or inserted into the plan, for example to avoid an overload caused by unexpected load growth, an unexpected request to coordinate with a Transmission project, or third-party generator interconnection requests.

1 **Q. How does the HVD Lines and Substations Capacity sub-program align with the**
2 **Reliability Roadmap?**

3 A. This sub-program is aligned with the “HVD Load Growth and Interconnection” component
4 of the Reliability Roadmap. Investments in this sub-program support the Company’s goals
5 of ensuring that the HVD system can serve electric peak demand, accommodate new
6 interconnections, and ensure current standards to support improved functionality of the
7 system.

8 **Q. What benefits will customers realize through the Company completing work in the**
9 **HVD Lines and Substations Capacity sub-program?**

10 A. Because the HVD system is the backbone infrastructure of the electric distribution network,
11 projects in this sub-program must be completed on an as-needed basis to serve customers
12 and maintain the safety and overall reliability of the grid. This sub-program ensures that
13 the HVD system has the capacity to accommodate potential changes to the load profiles
14 needed for new and changing technologies such as electrical vehicles and other potential
15 electric growth in the future due to emerging technologies. Although this sub-program is
16 not specifically designed to address system deterioration, investments in this sub-program
17 improve system reliability and safety, and prevent future overloads, which can trigger
18 dangerous wire downs and equipment failures due to exceedance of equipment interrupting
19 capability.

20 **Q. What investment categories are included in the HVD Lines and Substations Capacity**
21 **sub-program?**

22 A. The investment categories are:

- 23
 - Load Carrying Capabilities and Voltage Support

- New Interconnections
- Improved Functionality
- Coordination with Transmission
- ROW Procurement

Q. What projects are funded by the Load Carrying Capabilities and Voltage Support investment category?

A. The Load Carrying Capabilities and Voltage Support investment category contains projects that eliminate unacceptably low voltage, loadings above line and equipment ratings, and available short circuit above equipment interrupting capability. These capacity projects must be completed based on projected loading in power flow models to serve customers and maintain the safety and overall reliability of the grid. The Company studies the HVD system using power flow analysis to calculate the base power flow and voltages, and changes in power flow and voltages resulting from single outages for present and future versions of the HVD system. The HVD system model is updated annually, following summer peak loading and into the first quarter of the following year. The studies are performed in the second quarter each year, and projects are then developed to address identified projected issues before the issue occurs in subsequent years. SCADA information is also used to project future load on the HVD system. Through this process, HVD facilities are identified that would violate the HVD Planning criteria due to line or equipment overload, or due to unacceptably low voltage during base (normal) conditions at system peak load or during single (N-1 equipment out of service) outage conditions at 80% of system peak load. Outage conditions studied include single line, single transformer, single bus, and single generator outages. Also identified are interrupting devices where the available short circuit is

1 projected to exceed interrupting capability. The Company's plans to fix projected criteria
2 violations are tested in the models to ensure they fulfill their designed purpose.

3 **Q. How are projections of peak load developed?**

4 A. Each year, after summer peak conditions, the Company revises its load forecast to reflect
5 the most recent experience with customer peak usage. The load forecast is done at the
6 system and circuit levels and represents the simultaneous usage of all downstream
7 customers.

8 **Q. How does the Company project loading on individual elements of the electric system?**

9 A. For HVD elements, the Company's planning engineers allocate the system load to
10 individual substation loads using SCADA data. The Company's planning engineers then
11 use power flow modeling to identify loading on each element of the electric system. The
12 power flow model simulates how power flows on the electric system, based on the
13 fundamental laws of electricity. These models can identify loading on each element,
14 compare it with the capacity of that element, and provide the Company's Planning
15 Engineers with those instances where capacity is insufficient to meet projected loading.

16 **Q. How does the Company determine the capacity of individual elements of the electric
17 system?**

18 A. The Company's design engineers determine the capacity of elements based on manufacturer
19 or industry resource standards (i.e. IEEE). Multiple data sets and software programs are
20 used to assist in determining capacity of each element.

21 **Q. How are the Company's equipment ratings developed?**

22 A. Equipment ratings — essentially the capability of a piece of equipment — are developed to
23 ensure equipment is capable of handling peak hour loading over multiple hours, not just a

1 single peak hour. In other words, equipment ratings are based on an ability to handle load
2 at a particularly sustained loading level for a period. The Company bases its equipment
3 ratings on manufacturer or industry resource standards (i.e. IEEE).

4 **Q. Can you provide an example of a Load Carrying Capabilities and Voltage Support**
5 **Project?**

6 A. Yes. A recent example is from the Midland area, where forecasted loading was projected
7 to exceed the capacity of the 46 kV Coleman Lines and Warren 138/46 kV Substation for
8 certain transmission system contingencies. Alternatives considered included a transmission
9 level solution for the transmission company to construct a new 20+ mile long 138 kV line
10 and several transmission substation upgrades versus a distribution level solution for the
11 Company to rebuild 13.9 miles of the Coleman 46 kV line. Ultimately, the distribution
12 project to rebuild the Coleman 46 kV line was selected as it most directly addressed the
13 projected overloads and was the least cost alternative.

14 **Q. What projects are funded through the New Interconnections investment category?**

15 A. The New Interconnections category contains new interconnections to other utilities and
16 generation facilities that must be completed as requested by the interconnecting party. Costs
17 to interconnect other utilities and generation facilities to the Company's HVD system are
18 reimbursed by the other utilities or generators being interconnected.

19 **Q. Has the Company made any changes to the New Interconnections investment**
20 **category? If so, please explain why these changes were completed.**

21 A. Prior to 2024, the New Interconnections investment category also contained HVD
22 interconnections to LVD substations. For example, a new 46 kV line might be needed to
23 connect a new LVD substation to the existing HVD system. Starting in 2024, these HVD

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1 facilities needed to connect an LVD substation to the HVD system are included with the
2 LVD substation project in the applicable LVD substation sub-programs, which are
3 discussed by Company witness Partlan. This change was made to better align the planning
4 for scope, schedule, and budget for all portions of a project to the overall initiating need. In
5 other words, if an LVD substation project is planned, then the full scope for that LVD
6 substation project, including any needed HVD lines, will now all be contained within the
7 LVD substation project itself.

8 **Q. What projects are funded through the Improved Functionality investment category?**

9 A. The Improved Functionality category contains projects that are completed to meet changes
10 in standards and upgrades to protective schemes for Grid Operability/Reliability on a
11 planned basis over a period. An example of this is the Company alleviating substation
12 NESC working space issues systematically over a 10-year period. It is often coordinated
13 with other major projects as they occur at the same location. Configuration changes to
14 improve operability are made at the request of the Grid Management group or through
15 coordination with other major projects as they occur at the same location. As discussed
16 earlier in my direct testimony on the HVD Lines Reliability sub-program, the Improved
17 Functionality investment category includes line sensors through the end of the 2024
18 calendar year, after which they were shifted to HVD Lines Reliability.

19 **Q. What projects are funded through the Coordination with Transmission investment**
20 **category?**

21 A. The Coordination with Transmission projects, such as HVD relay upgrades associated with
22 transmission upgrades, must be coordinated with those transmission upgrade projects that

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1 require HVD upgrades to be completed as well. These are completed as needed over time
2 in conjunction with the transmission owner.

3 **Q. What projects are funded through the ROW Procurement investment category?**

4 A. When existing easements are insufficient, ROW Procurement projects are necessary to
5 procure land or land rights for HVD lines and substation sites across the HVD Capacity
6 capital sub-program prior to construction and can require significant lead time. Through
7 the process of monitoring and studying load profiles and planning for future infrastructure
8 rebuilds or replacements, properties are sought and procured to build electric infrastructure
9 at the right point in time needed to serve customers or meet infrastructure rebuild or
10 replacement project timelines.

11 **Q. Has the Company made changes to the ROW Procurement category within this**
12 **sub-program for calendar year 2024 and beyond?**

13 A. Prior to 2024, the ROW Procurement category within this sub-program contained ROW
14 procurement for all HVD ROW needs, including ROW needed for projects in other
15 sub-programs. For example, ROW needed for a new 46 kV line, to connect a new LVD
16 Substation, or for an HVD line or substation rebuild would have been included in HVD
17 Lines and Substations Capacity. Starting in 2024, these ROW acquisitions for projects in
18 other sub-programs are included within those other respective sub-programs. This change
19 was done to better align the planning for scope, schedule, and budget for all portions of a
20 project to the overall initiating need.

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Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery in the HVD Lines and Substations Capacity sub-program?

A. The Company is projecting in the bridge period HVD Lines and Substations Capacity capital expenditures of \$40,913,000, and test year expenditures of \$29,447,000, as shown in Exhibit A-116 (MPK-6), line 2. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 54 below.

FIGURE 54
HVD LINES AND SUBSTATIONS CAPACITY INVESTMENT CATEGORY
EXPENDITURES AND PROJECTS

Investment Categories	Bridge Period Capital	# Units	Test Year Capital	# Units	Benefits*
Load carrying capabilities and voltage support	\$16,494,000	4	\$7,701,000	3	Avoid overload, mitigate inadequate clearance, offset transmission costs, 978,507 customer minutes
Improved functionality	\$12,153,000	29	\$7,441,000	12	Regulatory compliance, mitigate inadequate clearance, new standards, safety, grid operability/reliability, 17,650 customer minutes
Coordination with Transmission	\$6,293,000	15	\$9,226,000	9	Contractual requirement to coordinate with Transmission projects
ROW procurement	\$5,972,000	8	\$5,079,000	3	Needed to support ROW needs for many projects
Total	\$40,913,000		\$29,447,000		

*NOTE: All customer minutes are summarized by project in Exhibits A-109 (MLH-3) and A-110 (MLH-4).

1 **Q. What is the basis for the requested spending level for the HVD Lines and Substations**
2 **Capacity sub-program in this filing?**

3 A. The requested spending levels for the bridge period and test year are based on the total of
4 all costs in the Company's workplan. The cost projections in this sub-program were
5 developed using derived costs, where available, that have been based on historical actuals
6 experienced for similar projects. In many cases, the costs are also further refined with
7 support from the Company's design and project management departments, taking into
8 consideration the specifics of each project such as the location, expected site conditions, and
9 up-to-date material and labor costs. The spending amounts for the bridge period and test
10 year are determined by the combined costs of individual projects and will allow the
11 Company to complete the projects listed, and deliver the benefits summarized above. The
12 capital projects planned for the bridge period and the test year, as well as their investment
13 categories, locations, and benefits to reliability are shown in Exhibits A-109 (MLH-3), page
14 9, and A-110 (MLH-4), page 9.

15 **Q. Exhibit A-109 (MLH-3), page 9, line 23, indicates that the requested bridge period and**
16 **test year spending amounts are higher than historical average. Are there projects in**
17 **the bridge period and test year that are driving this increase?**

18 A. Yes. The spending in both the bridge period and the test year is higher than the historical
19 average due to the increased amount of work needed in the sub-program, with several large
20 projects beyond typical historical levels. In the bridge period, one such project is the
21 Coleman 46 kV 14-mile rebuild project. This project is needed due to a generator being
22 connected to the transmission system in the area that would overload this line. Rebuilding
23 the Coleman line is a more cost-effective alternative than further transmission system

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1 upgrades to mitigate that same overload. This project is listed in Exhibit A-109 (MLH-3),
2 page 9, line 30. The bridge period also includes a project to rebuild 3.1 miles of the Larkin
3 46 kV line to address inadequate clearance and capacity. This project is listed in Exhibit
4 A-109 (MLH-3), page 9, line 31.

5 Other large projects needed in the test year are the Linden 46 kV line rebuild, needed
6 to address a projected overload on this line (see Exhibit A-110 (MLH-4), page 9, line 14);
7 and the Wealthy Street 138/46 kV Substation project needed to coordinate with a METC
8 Transmission project (see Exhibit A-110 (MLH-4), page 9, line 25).

9 **Q. What benefits will customers realize through the Company completing work in the**
10 **HVD Lines and Substations Capacity sub-program?**

11 A. Because the HVD system is the backbone infrastructure of the electric distribution network,
12 projects in this sub-program must be completed on an as-needed basis to serve customers
13 and maintain the safety and overall reliability of the grid. This sub-program ensures that
14 the HVD system has the capacity to accommodate potential changes to the load profiles
15 needed for new and changing technologies such as electrical vehicles and other potential
16 electric growth in the future due to emerging technologies. Although this sub-program is
17 not specifically designed to address system deterioration, investments in this sub-program
18 improve system reliability and safety, and prevent future overloads, which can trigger
19 dangerous wire downs and equipment failures due to exceedance of equipment interrupting
20 capability.

1 **Q. What has been the historical actual spending in the HVD Lines and Substations**
2 **Capacity sub-program for the past five years?**

3 A. The Company's historical actual spending in the HVD Lines and Substations Capacity
4 sub-program for the past five years is shown in Figure 55 below.

FIGURE 55
HVD SYSTEM CAPACITY HISTORICAL SPENDING

2020	2021	2022	2023	2024	5-Year Average
\$19,247,000	\$17,365,000	\$29,292,000,	\$25,805,000	\$27,163,000	\$23,775,000

5 **Q. Please explain year-over-year variation in spending in this program.**

6 A. Projects in this sub-program have a variety of specific needs and in-service dates.
7 Additionally, projects in this sub-program vary greatly depending on the required system
8 upgrades, ranging from \$10,000 or less for upgrading/replacing smaller equipment to
9 several million dollars where an entire new substation or HVD line is needed, as can be seen
10 in the project lists in Exhibits A-109 (MLH-3), page 9, and A-110 (MLH-4), page 9.
11 Therefore, year-over-year variation in this program is driven by the timing needs of
12 completing projects with such a great variance in scope and costs. Many of the projects are
13 also driven either by a need to provide capacity before equipment overloads or by
14 coordination with other parties, such as transmission owners, other utilities, and generation
15 interconnections. Therefore, changes in load projections and changes in coordinating
16 project schedules can drive variability in timing of spending. Combined with the very large
17 costs of some projects, this can shift large amounts of spending from year to year.

1 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
2 **sub-program?**

3 A. No, the unit for this sub-program is projects, and the projects undertaken are specifically
4 tailored and unique to only what must be performed, so the scope and cost of each project
5 varies from project to project. There is a wide variance among work required ranging from
6 approximately \$10,000 or less for upgrading/replacing smaller equipment to as high as
7 \$10,000,000 or more where an entire new substation or HVD line is needed.

8 **b) LVD Substations Capacity**

9 **Q. Please explain what capital projects, activities, and other types of work will be enabled**
10 **by expenditures in the LVD Substations Capacity sub-program.**

11 A. The LVD Substations Capacity sub-program ensures the long-term safe and reliable
12 operation of the Company's electric distribution LVD substations. The necessary capital
13 expenditures include investments to install new substations or substation equipment, and to
14 upgrade existing substations or substation equipment to ensure customer electric loads are
15 served within the operating capacity of the installed substation equipment (i.e. transformers,
16 fuses, reclosers, regulators, and switches). The LVD Substations Capacity investments are
17 divided into two categories: new substations and existing substation capacity increases.

18 **Q. What other work will be completed in the LVD Substation Capacity sub-program?**

19 A. Starting in 2024, two work items were incorporated into the LVD Substation Capacity
20 sub-program. HVD line work and ROW procurement associated with new and existing
21 LVD Substation Capacity sub-program projects had been part of the HVD Lines and
22 Substation Capacity sub-program investments. To improve investment categorization and
23 project cost tracking, HVD line work and ROW procurement associated with LVD
24 Substation Capacity projects are included in the LVD Substation Capacity sub-program.

1 **Q. Did the Company consider any alternative approaches to project selection that could**
2 **help achieve the Reliability Roadmap objectives?**

3 A. Yes. Alternatives typically considered for each project include:

- 4 (i) transferring load to an adjacent and less loaded substation or line;
- 5 (ii) upgrading equipment or lines to provide the needed capacity;
- 6 (iii) building a new LVD substation to share the load capacity; and
- 7 (iv) connecting to a different HVD source.

8 Each project is selected based upon its effectiveness at solving the identified problem, the
9 cost of the project, and the relative benefits.

10 **Q. What benefits will customers realize through the Company completing work in the**
11 **LVD Substations Capacity sub-program?**

12 A. LVD Substations Capacity investments are necessary for the overall operation and
13 reliability of the electric distribution system by preventing future overloads and addressing
14 existing overloads, which would eventually result in equipment failure and customer
15 outages, while ensuring the Company has adequate capacity on the distribution system to
16 serve customer load. The number of customers benefitting from each project in this
17 sub-program in the bridge period are identified in the Benefit Type and Benefit columns of
18 Exhibit A-109 (MLH-3), page 10, and for the test year, listed in Exhibit A-110 (MLH-4),
19 page 10.

20 **Q. How does the Company identify LVD Substations Capacity projects?**

21 A. LVD Substations Capacity planning projects are developed to respond to peak load
22 conditions. Monitoring with DSCADA and analysis are done to identify situations where a
23 component of the LVD substation has experienced an overload of its rated capacity. These

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1 substation components are selected for a capacity upgrade project. If necessary, LVD
2 substation capacity projects are prioritized to address the highest overloads in advance of
3 lower overloads, with adjustments made for other factors such as historical reliability,
4 customer mix, and safety impact. When assessing loads, the Company prudently considers
5 actual and known new business load additions.

6 **Q. Please identify the projects that will be accomplished with the requested spending level**
7 **in the LVD Substations Capacity sub-program.**

8 A. The Company has identified projects for the bridge period, listed in Exhibit A-109 (MLH-3),
9 page 10, and for the test year, listed in Exhibit A-110 (MLH-4), page 10. Projected project
10 costs were determined based on the specific work scope for each project and historical costs
11 from similar projects. These exhibits also identify the location and benefits of the projects.

12 **Q. Are NWS considered in the LVD Substations Capacity sub-program?**

13 A. Yes. The Company has been exploring the potential for considering NWS as another
14 alternative LVD substation capacity solution in recent years. Through recent pilots, the
15 Company has refined its selection criteria for identifying potential LVD substations where
16 NWS can be considered, with criteria including the peak load reduction needed, the
17 timeframe of the projected need, customer mix, and other factors. The Company has already
18 begun considering NWS, including solar and batteries, in some of its concept approvals for
19 projects in this sub-program. However, as Company witness Kelly discusses in his direct
20 testimony, the Company is also still early in the process of exploring how NWS can solve
21 capacity and reliability issues on the system, and the Company is developing a new pilot in
22 2025 to better understand NWS applications.

1 **Q. What are the Company's projected bridge period and test year spending levels, for**
2 **which it is requesting cost recovery, in the LVD Substations Capacity sub-program?**

3 A. The Company is projecting LVD Substations Capacity capital expenditures of \$29,656,000
4 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 24, column (k), and
5 \$22,251,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 24, column (l). The
6 Company's historical actual spending in the LVD Substations Capacity sub-program, along
7 with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3),
8 line 24.

9 **Q. How did the Company develop its projected expenditures in this sub-program?**

10 A. The Company's projected spending for the LVD Substations Capacity sub-program is based
11 on the Company's identified capacity needs and planned projects to mitigate planning
12 criteria violations. The bridge period spending amount was determined based on the amount
13 of investment needed to complete the projects identified.

14 Project costs were determined based on the specific work scope for each project and
15 historical costs from similar projects. This level of work and the associated spending are
16 adequate to meet the sub-program objective to serve customer electric loads within the
17 operating capacity of the installed substation equipment, thereby ensuring the long-term and
18 reliable operation of the electric distribution LVD substations.

19 **Q. Please explain how the capital expenditures projected for the bridge period and the**
20 **test year for this sub-program will be allocated across the two investment categories.**

21 A. The Company is projecting unit and capital expenditures in the bridge period and test year
22 for each investment category as identified in Figure 56.

FIGURE 56
LVD SUBSTATIONS CAPACITY INVESTMENT CATEGORY EXPENDITURES AND PROJECTS

Investment Categories	Bridge Period Capital	Bridge Period # of Projects	Test Year Capital	Test Year # of Projects
New substations	\$5,136,000	4	\$20,303,000	11
Existing substations projects	\$24,520,000	19	\$1,948,000	4
Total	\$29,656,000	23	\$22,251,000	15

Q. Please explain the year-over-year variation in spending in this sub-program.

A. The spending variation in the LVD Substations Capacity sub-program from 2020 to 2024 was based upon the types of projects that were required to address the capacity issues in those years.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. Average unit cost is not a good measure of spending to predict the cost of an individual project for this sub-program due to the variation in specific work scopes needed for each project.

3. ELECTRIC OTHER PROGRAM

Q. What is included in the Electric Other Program?

A. Company witness Kelly introduces the Electric Other Program in his direct testimony. The Electric Other Program includes the following sub-programs in the test year:

- Computers and Equipment
- System Control Projects
- Grid Technologies

The Electric Other Program also includes the Tools sub-program, which is addressed by Company witness Partlan in her direct testimony.

a) Computers and Equipment

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the Computers and Equipment sub-program.

A. The Computers and Equipment sub-program consists of the capital costs to purchase and replenish computer equipment for electric distribution purposes.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the Computers and Equipment sub-program?

A. The Company is projecting bridge period capital expenditures of \$75,000 in this sub-program, as shown in Exhibit A-113 (MPK-3), line 42, column (k). This spending is primarily for new field devices. The Company is projecting test year capital expenditures in this sub-program of \$75,000, as shown in Exhibit A-113 (MPK-3), line 42, column (l). As shown in Exhibit A-113 (MPK-3), line 42, column (m), this amount is lower than the five-year average spending for this sub-program.

Q. Why were spending levels in this sub-program significantly higher in 2022?

A. Higher spending levels in 2022 were related to a Scheduling Optimization project. The purpose of the Scheduling Optimization project is to better ensure the Company gets the right crew on site at the right time, so that field work can be completed right the first time and in a safe manner. In 2022, the Company developed and deployed a new digital tool called "iSchedule" as a part of this effort. This project was addressed in Case No. U-21389.

b) System Control Projects

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the System Control Projects sub-program.

A. The System Control Projects sub-program consists of projects to improve management of the distribution system, by improving operations of control centers, streamlining operations, and improving remote control capabilities to improve safety and reliability. This work includes operating technology enhancements and operations center modifications.

Q. What is included in operating technology enhancements?

A. Operating technology enhancements improve functionality and operations of the:

- System Control Center (“SCC”) - Monitor and maintain the 46 kV and 138 kV HVD Systems;
- Distribution Control Center (“DCC”) – Monitor and maintain LVD Substations and 3-phase backbone of the LVD system; and
- Work Management Centers (“WMC”) - Monitor and maintain the LVD system and responsible for outage restoration by managing crews on the LVD system.

These three groups are responsible for monitoring the system and ensuring a reliable power supply for all customers. To manage a system of this size, these centers use technology specifically designed for real-time operations. Specific enhancements can vary from year to year.

Q. What is included in operations center modifications?

A. This consists of additional equipment and infrastructure to improve the Emergency Operations Center (“EOC”). These initiatives are typically identified during the after-action-reviews (“AAR”) for each event. Examples of these kind of initiatives include small upgrades to office spaces to accommodate personnel and larger computer monitors to increase situational awareness.

1 **Q. What benefits will customers realize through the Company completing work in the**
2 **System Control Projects sub-program?**

3 A. Improving monitoring and control capabilities on the distribution system helps streamline
4 operations and reduce the impact of any single fault, reducing interruptions for customers.
5 The technology enhancements and control room modifications will better enable employees
6 to provide safe and reliable electricity.

7 **Q. What is the basis for the Company's projected investment in System Control Projects**
8 **in the instant case?**

9 A. In Case No. U-21585, the Company projected test year investment of \$279,000 for this
10 sub-program, and this amount was approved by the Commission. In the instant case, the
11 Company is maintaining projected investment levels at approximately the same amount, as
12 shown in Exhibit A-113 (MPK-3), line 44.

13 **Q. What has been the historical actual spending in the System Control Projects**
14 **sub-program for the past five years?**

15 A. The Company's historical actual spending is shown in Figure 57 below.

FIGURE 57
SYSTEM CONTROL PROJECTS HISTORIC EXPENDITURES

2020	2021	2022	2023	2024	5-Year Average
\$975,812	\$1,193,498	\$2,179,436	\$41,000	\$896,000	\$1,057,000

16 **Q. Please explain the year-over-year variation in spending in this sub-program.**

17 A. Spending in this sub-program is inherently variable on a year-over-year basis primarily
18 because this sub-program consists of discrete one-time projects that will not necessarily be
19 repeated from year to year. Given technology programs may cost a relatively large amount

1 to purchase in one year, but then once purchased there is no additional spending for that
2 technology in subsequent years. Test year spending in this sub-program is lower than the
3 five-year historical average for two primary reasons. First, as the Company plans to
4 transition to a Unified Control Center, less investment is needed in the existing facilities
5 that will be replaced. Second, work that has historically been performed in the HVD
6 Operations Projects investment category is being transitioned largely to the HVD Lines
7 Reliability sub-program, reducing the total amount spent in System Control Projects.

8 **B. Unplanned Spending Programs**

9 **1. HVD STRATEGIC CUSTOMERS NEW BUSINESS**

10 **Q. What is the purpose of the New Business Program?**

11 A. The overall New Business Program includes the capital costs of connecting new
12 commercial, industrial, and residential customers to the Company's distribution grid, as
13 discussed by Company witness Kelly in his direct testimony. Because of the Company's
14 obligation to serve customers in its service territory, the Company generally is required to
15 provide the requested interconnections.

16 **Q. Please explain what capital projects, activities, and other types of work will be enabled
17 by expenditures in the HVD Strategic Customers New Business sub-program.**

18 A. The HVD Strategic Customers New Business sub-program consists of the capital costs to
19 meet the new business needs of large C&I customers that are too energy intensive to be
20 served by the area LVD system, addressing both existing customers and potential new
21 customers to locate a new facility in Michigan. Typical investments for this program
22 include dedicated substations and interconnections of dedicated substations to the HVD
23 system with poles, conductors, and metering to connect new C&I customers.

1 **Q. How does the Company plan projects and develop investment projections in this**
2 **sub-program?**

3 A. Projected test year spending amounts are based on planned projects to meet customer
4 commitments, plus projects with a high probability of moving forward in the near future,
5 such that bridge or test year spending amounts would be needed, as discussed in more detail
6 below. These costs are net of any expected contributions made to the Company by
7 customers in support of their project. Customer service inquiries in this sub-program are
8 continuous and are driven by customer business needs. Unlike many of the Company's
9 other capital programs, this sub-program and its timing of projects and investments are
10 driven to meet the needs and expectations of specific customers. The timeline from a
11 completed customer agreement to a final connection can vary from six months to two or
12 more years. While some projects are known well enough in advance to be captured in a rate
13 case filing, in other cases they are not.

14 **Q. Please explain how the Company identifies projects to account for spending in this**
15 **sub-program.**

16 A. The Company identifies projects as they are requested by customers. Customers typically
17 contact the Company's Business Customer Care team, who refers the customer to the HVD
18 planning engineer for the corresponding geographic location. The customer will identify
19 their location, proposed new maximum electrical demand, a proposed schedule for the new
20 electric load to come online, as well as other information. The HVD planning engineer
21 performs studies and develops conceptual cost estimates for any required new or upgraded
22 Company facilities to serve the new load, including any Contribution in Aid of Construction
23 ("CIAC") costs applicable to the customer. The conceptual cost estimates are developed by

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the Company's project management team using derived costs, where available, based on historical actual costs for similar projects. The costs are also further refined with support from the Company's design and project management departments prior to customer agreements being executed, taking into consideration the specifics of each project such as the location, expected site conditions, and up-to-date material and labor costs. If costs are agreed to by the customer, a schedule for the work is developed.

Q. What are the Company's projected bridge year and test year spending levels, for which it is requesting cost recovery, in the HVD Strategic Customers New Business sub-program?

A. The Company is projecting HVD Strategic Customers New Business capital expenditures of \$90,045,000 in the bridge period, and \$43,860,000 in the test year, as shown in Figure 58 below.

FIGURE 58
HVD STRATEGIC CUSTOMERS NEW BUSINESS INVESTMENT CATEGORY
PROJECTED EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test year # of Units	Benefits
Projects	\$90,045,000	6	\$43,860,000	4	Obligation to Serve, Economic/Community Impact (see Figure 43)
Total	\$90,045,000	6	\$43,860,000	4	

Q. What is the basis for the Company's requested spending level for the HVD Strategic Customers New Business sub-program in this filing?

A. The projected spending for the bridge period and the test year is primarily based on projects to which customers have committed to moving forward. These projects are listed in Exhibit A-109 (MLH-3), page 11, and Exhibit A-110 (MLH-4), page 11.

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1 **Q. Have customers committed to moving forward with all of the listed projects?**

2 A. Yes, with one exception. Exhibit A-109 (MLH-3), page 11, line 2, refers to a new 138 kV
3 dedicated customer's substation in northwest Michigan. This project was associated with a
4 customer that did have a fully committed contract with the Company, and the Commission
5 approved spending on this project in Case No. U-21585. However, in April 2025 this
6 contract was terminated after the customer's postponement of construction continued for
7 more than 12 months. Because a contract existed and because expenditures had been
8 approved by the Commission, the Company has already made some expenditures in the
9 bridge period, and the Company is seeking recovery of these expenditures that were made
10 in good faith. Pursuant to that termination and language in the customer's contract with the
11 Company, the customer is required to reimburse the Company for costs incurred for the
12 project. Specifically, the customer is required to pay the Company the entire cost for work
13 performed, materials not salvaged, and all reasonable cancellation expenses incurred to
14 provide service, without interest, less payment made by the customer. If and when the
15 Company recovers these costs from the customer, that money will be credited to this
16 sub-program and netted back out of rate base.

17 **Q. Is there any other spending in Exhibit A-109 (MLH-3), page 11, or Exhibit A-110**
18 **(MLH-4), page 11, that is not tied to projects to which customers have fully**
19 **committed?**

20 A. The Company also has some spending included for certain high probability projects that are
21 in active contract negotiation that are very likely to move forward in the near future, such
22 that the Company must invest in the bridge period and test year in order to ensure that
23 customer needs can be met.

1 **Q. Please further discuss this “high probability projects” item that is listed in Exhibit**
2 **A-109 (MLH-3), page 11, line 7, and Exhibit A-110 (MLH-4), page 11, line 7.**

3 A. The Company is engaged in multiple inquiries, working in conjunction with the Michigan
4 Economic Development Corporation (“MEDC”) and other local economic development
5 groups, to accommodate prospective new large industrial customers considering siting in
6 Michigan. The high probability projects item represents the C&I developments that the
7 Company is in active contract negotiations on, and which have a high probability of moving
8 forward in the near future, requiring spending in both the bridge period and/or the test year.
9 For these high probability projects, the customer either has accepted a commitment offer
10 letter from the MEDC and/or has identified a specific site in the Company’s service territory
11 for location. These projects have long lead times in terms of ordering materials and other
12 logistical considerations, and prospective large customers need the certainty that they will
13 be able to connect to the Company’s system on their schedule. Consequently, for these high
14 probability projects the Company often must begin purchasing materials and doing other
15 work in advance.

16 **Q. Can you provide any relevant benchmarking or industry references outside of the**
17 **Company’s specific experience that supports the need to procure long lead material**
18 **and do other advance work to accommodate new and expanding customers?**

19 A. Yes. The Site Selectors Guild, an association of global professional site selection
20 consultants, partnered with Development Counsellors International to complete *The State*
21 *of Site Selection 2024* report¹, a primary research study that identifies the top trends
22 impacting the facility location decision-making process in the United States and globally.

¹ Available at <https://siteselectorsguild.com/research/the-state-of-site-selection-2024/>.

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1 It provides a thorough review of the background and collective industry knowledge that has
2 historically influenced site selection decisions. It also provides a sound basis for the
3 Company's approach to responding to new business requests. The study found that 87% of
4 Guild members strongly agree that resource shortages (including with utilities) have
5 challenged or compromised project timelines (page 10). "Utilities/Infrastructure" continues
6 to be identified as a top factor impacting the site selection industry in 2024 (page 11).
7 Furthermore, 79% of Guild members identified "Utilities/Infrastructure" as *the* top factor
8 impacting site selection in 2024 for Industrial customers, and 64% identified the availability
9 of development-ready sites as the third most critical factor to industrial customers (page 12).
10 Almost all Guild members that participated (96%) agreed that access to development-ready
11 sites will significantly impact the future of industrial projects (page 18). The report
12 recognizes that there is a scarcity of industrial sites with 82% of Guild members strongly
13 agreeing that for industrial projects, the availability of development-ready sites with
14 sufficient infrastructure capacity is the top location driver in 2024 (page 20). Directly
15 related to the state of utilities and infrastructure, 98% of Guild members believe access to
16 sufficient electric capacity will significantly impact the future of industrial projects (page
17 35). Guild members also agree that the most significant impacting factors to industrial
18 projects are electric power capacity, with a 4.7 significance rating (out of a 5-point scale of
19 significance) and access to development-ready sites at 4.6 significance rating (page 37).
20 98% of Guild members that participated in this study are in agreement that electric power
21 capacity will significantly impact the future of industrial projects (page 38).

22 The quotes below from the study are consistent with the Company's experience:

23 In the U.S., the supply of industrial sites with adequate labor,
24 utilities and access has been significantly reduced due to

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1 economic growth in the industrial sector over the last 10 to
2 15 years. In terms of the site selection process, intensified
3 screening of sites at early stages of projects is critically
4 important to verify fatal flaws. [Mark Williams, Strategic
5 Development Group Inc. (page 17 of the report)]

6 The biggest challenge facing the industrial market is the lack
7 of development-ready sites with desired available utility
8 capacity. When utilities require upgrades to meet capacity
9 needs, you are looking at a 24- to 36-month timeline for that
10 to occur, which rarely meets a company's plant startup
11 timeline these days. Everything is moving at a faster pace,
12 so if you are a community that truly wants to attract new jobs
13 and investment to your community, you must get your sites
14 and infrastructure prepared ahead of these search inquiries.
15 There is just no way around it. [Michelle Comerford,
16 Biggens Lacy Shapiro & Company (page 23 of the report)]

17 High energy demands with many of the EV/clean
18 fuel/semiconductor projects, along with the transition away
19 from carbon-based generation, are causing a significant
20 stress on the grid causing delays in project timelines. [John
21 Longshore, Newmark (page 36 of the report)]

22 So many projects have required massive amounts of electric
23 power and often other utilities, which has strained capacity
24 in nearly all locations that are typically attractive to
25 manufacturers.....Lengthy waits to get transformers –
26 sometimes quoted at 36 months now – quickly eliminates
27 otherwise top locations. Smaller to midsized projects, which
28 could become the norm again after this big push on electric
29 vehicles, semiconductors and solar production abates, are a
30 bit less impacted and have more choices, but the capacity
31 constraints will start affect their choices and certainly their
32 costs. [Phil Schneider, Schneider Strategy Consulting LLC
33 (page 41)]

34 **Q. What has been the historical actual spending in the HVD Strategic Customers New**
35 **Business sub-program for the past five years?**

36 **A.** The Company's historical actual spending in this sub-program for the past five calendar
37 years is shown in Figure 59 below.

FIGURE 59
HVD STRATEGIC CUSTOMERS NEW BUSINESS HISTORIC EXPENDITURES (\$000)

2020	2021	2022	2023	2024	5-Year Average
\$4,038	\$20,268	\$4,280	\$11,071	\$57,836	\$19,499

1 **Q. Why does historical spending in this sub-program show significant year-to-year**
2 **variation?**

3 A. Spending in this sub-program can be inherently variable from year to year because the
4 projects and investments undertaken are relatively few and are specifically tailored to the
5 needs of the customers requesting the work. This was particularly illustrated in 2021 and
6 2024, when the Company worked on a couple of large customer projects in this sub-program
7 that accounted for the higher costs in those years. The amount of anticipated load and
8 redundancy requirements determines the required number and size of large substation
9 transformers, which is typically a large driver of costs in this sub-program. For example,
10 one of the large projects that occurred in 2024 was for a new 138-kV four-transformer
11 dedicated customer substation with four 75 MVA transformers, with project spending of
12 approximately \$18 million in 2024, and expected total project spending of \$45.6 million
13 over three years. Conversely, a project in 2020 for a new single-transformer dedicated
14 customer substation with a 30 MVA transformer had a total project cost of about
15 \$3.5 million. There can also be some projects that are relatively minor upgrades required to
16 serve smaller customers that cost less than \$100,000. The work completed in this
17 sub-program is performed to provide new or upgraded facilities required to serve new or
18 existing customers.

1 **Q. Why is the requested spending level for the bridge period and the test year greater**
2 **than the historical spending in this sub-program?**

3 A. As stated above, spending in this sub-program is based on unique customer requests and
4 projects that are tailored to the needs of the customer requesting work. Similar to 2021 and
5 2024, but on an even larger scale, the bridge period and the test year contain several large
6 projects that are needed to serve several very large customers. These include a new larger-
7 than-typical 138 kV dedicated customer substation needing two 75 MVA transformers to
8 serve a large customer in southern Michigan; a new larger-than-typical 138 kV dedicated
9 customer substation needing four 75 MVA transformers to serve a large customer in east
10 Michigan; a new larger-than-typical customer requiring two 138 kV dedicated customer
11 substations needing two 75 MVA transformers and three 150 MVA transformers to serve a
12 large customer in west Michigan; a new larger-than-typical 138 kV dedicated customer
13 substation needing two 150 MVA transformers in southeast Michigan; and a new 46 kV
14 customer substation to serve a customer in west Michigan. These span both the bridge
15 period and the test year with larger than historical spending required to complete these
16 projects. The projected spending amounts for these projects are shown in Exhibit A-109
17 (MLH-3), page 11, and Exhibit A-110 (MLH-4), page 11.

18 **Q. What benefits do customers receive through the Company completing work in the**
19 **HVD Strategic Customers New Business sub-program?**

20 A. The investments in this sub-program are necessary for C&I customers to expand their
21 facilities, allowing those customers to further develop their businesses. This also benefits
22 the broader economy of the state of Michigan. Increased large new customer connection
23 and load additions provide the benefits of job development, and other state and local revenue

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streams associated with business expansion. Figure 60 below illustrates examples of the benefits and impacts of two committed projects in progress (included in the bridge period and test year) and the associated community impact.

FIGURE 60
HVD STRATEGIC CUSTOMERS NEW BUSINESS RECENT PROJECT IMPACTS

Project Name	Community Impact
New 138 kV dedicated customer Substation in southern Michigan	The customer is constructing a new electric vehicle battery manufacturing facility. The project has the potential to result in the creation of up to 1,700 new jobs and a capital investment of up to \$2.6 billion. Up to \$29.7 billion in new personal income could be generated over 20 years by the direct, indirect, and induced jobs that this opportunity will create.
New 138 kV dedicated customer Substation in east Michigan	The customer announced and will be constructing a new manufacturing facility. The project has the potential to result in the creation of up to 1,100 new jobs paying an average wage of over \$28/hour and over \$900 million in private investment. The project is expected to spur spin-off investments and redevelopment, as well as \$5.6 billion in new personal income over the next 20 years.

Q. Does an average unit cost accurately reflect the expected spend per project for this sub-program?

A. No. The historical unit costs for this sub-program reflect projects that vary significantly in size and scale. Each project in this sub-program is specifically designed to meet the needs of the individual C&I customer who requests the project.

2. **METRO NEW BUSINESS**

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the Metro New Business sub-program.

A. The Metro New Business sub-program responds to electrical energy needs of new construction and existing metered locations served by the Company's Metro underground territories. The Company typically needs to extend both the underground civil infrastructure, such as ductwork, and the electrical system to accommodate new business requests.

Q. How does the Company generally handle new business requests on the Metro system?

A. Metro New Business customers are connected to the system at no cost, in accordance with rate administration and billing rules in the Company's MPSC-approved tariffs, specifically Section C6.2 Underground Policy, Part F. These customers commonly fall into two categories: (i) *primary service*, typically large commercial, government, and healthcare facilities; and (ii) *secondary service*, typically commercial retail use, mixed use, or residential buildings in accordance with the Company's MPSC-approved tariffs, specifically C1.6 General Provisions of Service and C4.3 Application of Residential Usage and Non-Residential Usage.

Q. What benefits will customers realize through the Company completing work in the Metro New Business sub-program?

A. Metro New Business projects primarily benefit the customers being connected. Service connections vary by electrical demand. Primary services are typically provided in a loop feed, primary selective, or split bus design that provides reliable service. Secondary services are radial in nature and sized to the service meter and customer electrical panel size to allow for future electric growth without subsequent upgrades. Economic growth in the six metro

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downtowns depend on the ability of new residential and commercial customers to access utilities, including electricity.

As with other work in the New Business Program, all customers ultimately benefit from the load growth driven by new customers, as system-wide fixed costs are spread across a broader base. The projected spending level will allow the Company to provide a new service installation to every customer who requests it.

Q. How does the Company identify Metro New Business projects?

A. The Company identifies projects as they are requested by customers, as is common throughout the New Business Program. The Company has identified projects needed to fulfill customer requests for the bridge period, which are listed in Exhibit A-109 (MLH-3), page 12. The Company has also identified projects, for the test year, which are listed in Exhibit A-110 (MLH-4), page 12. Projected project costs were determined based on the specific work scope for each project and historical costs from similar projects.

Additionally, the Company is aware of several prospective projects that could progress and require additional investment in the test year. The Company is holding ongoing discussions with these customers, including:

- Continuation of construction of a 380,000 square-foot event center and arena in Kalamazoo;
- Continuation of construction of the 10 acre, 12,000 seat Acrisure Amphitheater in Grand Rapids;
- Re-development of existing vacant buildings to mixed-use in Jackson;
- Numerous new mixed-use high-rise type buildings in Grand Rapids;
- A 200-unit apartment complex in Flint; and
- The new zoned planned unit development in Saginaw for the Saginaw Medical Diamond medical offices and mixed-use buildings.

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1 **Q. Are there projects that are not currently known, but that could be reprioritized to take**
2 **place during the test year, if circumstances change?**

3 A. While Metro New Business projects can be identified in advance on some occasions, project
4 timelines can be fluid because customers' own development timelines often change in
5 response to various factors. The projects listed in the exhibits are those that the Company
6 expects to perform in the bridge period and test year. However, it is possible that one or
7 more customers could request a project for 2026 or later, and then subsequently request the
8 Company perform the work sooner if the customer has a change in timeline.

9 **Q. What are the Company's projected bridge period and test year spending levels, for**
10 **which it is requesting cost recovery, in the Metro New Business sub-program?**

11 A. The Company is projecting Metro New Business capital expenditures of \$6,453,000 in the
12 bridge period, as shown in Exhibit A-113 (MPK-3), line 4, column (k), and \$7,917,000 in
13 the test year, as shown in Exhibit A-113 (MPK-3), line 4, column (l). The Company's
14 historical actual spending in the Metro New Business sub-program, along with the bridge
15 period and test year projections, are shown in Exhibit A-113 (MPK-3), line 4.

16 **Q. How does the Company develop its projected expenditures in this sub-program?**

17 A. In some cases, customers contact the Company in advance, allowing for Metro New
18 Business project costs to be determined and planned for in longer-range spending forecasts.
19 However, even with advance notice, customers' respective developments may take years to
20 come to fruition, as customers seek funding and address other issues relative to economic
21 development in urban core areas. Therefore, even advance notice Metro New Business
22 projects may not be completed on the originally proposed timeline. In other cases,
23 customers contact the Company later in their development process, with desired service

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1 within that same year, meaning those Metro New Business project costs cannot be
2 accounted for in longer-term forecasting. Therefore, the Company also uses analysis of
3 historical spending levels to forecast the level of investment needed in this sub-program.
4 The Company's projected bridge period and test year spending level in Metro New Business
5 is in line with recent experience. There have been many inquiries, in addition to the
6 identified projects, supporting that the projected Metro New Business expenditures for the
7 test year will be higher than the past three years.

8 **Q. Please explain the year-over-year variation in spending in this sub-program.**

9 A. The Company's recent investment in Metro New Business was at its highest in 2024, as
10 there was significant economic development and urban renewal, with corresponding
11 construction work, in several of the downtown areas served by the Company's Metro
12 systems. For example, in Grand Rapids the amphitheater civil project required an
13 investment of approximately \$3,450,000 and the first phase of civil work for the Kalamazoo
14 Event Center required an investment of approximately \$4,830,000. These higher than
15 historical costs were mainly driven by expansion of the Metro system to serve these new
16 business loads. The Metro New Business expenditures in 2022 were lower than the prior
17 five years due to project developer delays related to post-pandemic supply chain and
18 inflationary pressures, and lack of construction labor resources. Investment in 2023 was
19 lower than average as well due to project developer delays due to inflationary pressures and
20 lack of construction labor resources.

1 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
2 **sub-program?**

3 A. No. Average unit cost is not a good measure to project the cost of a project in this
4 sub-program. Metro projects have a wide variance in size, scope, and work required,
5 ranging from \$100,000 to as high as \$5,000,000 per project.

6 **3. HVD LINES AND SUBSTATIONS DEMAND FAILURES**

7 **Q. What is the purpose of the Demand Failures Program?**

8 A. The overall purpose of the Demand Failures Program is to address issues related to customer
9 interruptions and failures of equipment on the distribution system, as discussed by Company
10 witness Kelly in his direct testimony. When the Company replaces failed equipment, the
11 associated capital expenditures are part of the Demand Failures Program. The work in the
12 Demand Failures Program is emergent; it is planned, prioritized, and completed as issues
13 arise, with specific projects not planned far in advance. The HVD Lines and Substations
14 Demand Failures sub-program specifically addresses failures on HVD lines and substations.

15 **Q. Please explain what capital projects, activities, and other types of work will be enabled**
16 **by expenditures in the HVD Lines and Substations Demand Failures program.**

17 A. The HVD Lines and Substations Demand Failures sub-program supports the capital
18 replacement of failed 46 kV and 138 kV lines and substation equipment to restore customer
19 service and maintain reliability. This sub-program replaces assets that have failed in the
20 field, including HVD substation equipment, HVD poles and switches, and HVD cross-arms
21 and insulators. The HVD Lines and Substations Demand Failures sub-program consists of
22 the following investment categories addressing actual failures:

- 23
 - Pole replacements

- Pole top assembly replacements
- Switch (including MOABS replacements)
- Miscellaneous other replacements
- HVD substation failure projects

The first four cited investment categories support projects on HVD lines.

Q. What types of investments are included in the HVD substation failure investment category?

A. The HVD substation failure investment category supports the replacement of equipment and infrastructure that has failed within an HVD substation and includes (but is not limited to) power transformers, circuit breakers, circuit switchers, capacitors, switches, bushings, station batteries/chargers, regulators, voltage transformers, and facilities (such as fences, gates, and driveways).

Q. What benefits will customers realize through the Company completing work, in the HVD Lines and Substations Demand Failures sub-program?

A. This sub-program is essential for the restoration of service to customers for the Company to meet its obligation to serve. As mentioned above, this sub-program is also utilized to address failed assets as they are identified prior to those failures causing an interruption to customers. The projected bridge and test year amounts provide for the level of investment necessary in HVD Lines and Substations Demand Failures needed to support capital repair or replacement of projected failed HVD equipment to address interruptions and meet the Company's obligation to serve customers.

In the majority of HVD Lines failures, customers are interrupted, and the Company must restore those customers as quickly and safely as possible. In 2024, there were 46 HVD

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1 Line failures with an average of 2,750 customers interrupted per event, not including MED
2 outages. For those situations where an HVD line failure occurs and customers are not
3 interrupted, such failures put the system into a non-standard configuration, reducing system
4 resiliency, that would likely result in a much larger outage if a second failure occurs. For
5 HVD substations, outages to customers due to individual equipment failures are much rarer
6 due to redundancies in the substations but they can be of significant size when they do occur.
7 A 2024 failure of an oil circuit breaker at Verona substation near Battle Creek resulted in
8 extended outages for 5,000 customers for more than 14 hours. Even more critical was the
9 loss of system resiliency and redundance that prevented quick isolation of more than an
10 additional 8,700 customers who were then without power for more than 22 hours. When an
11 individual piece of equipment in a substation fails, the Company still needs to address that
12 failure, even if no customers are interrupted, in order to maintain levels of redundancy.

13 **Q. How does the Company identify and prioritize HVD Lines and Substations Demand**
14 **Failures sub-program projects?**

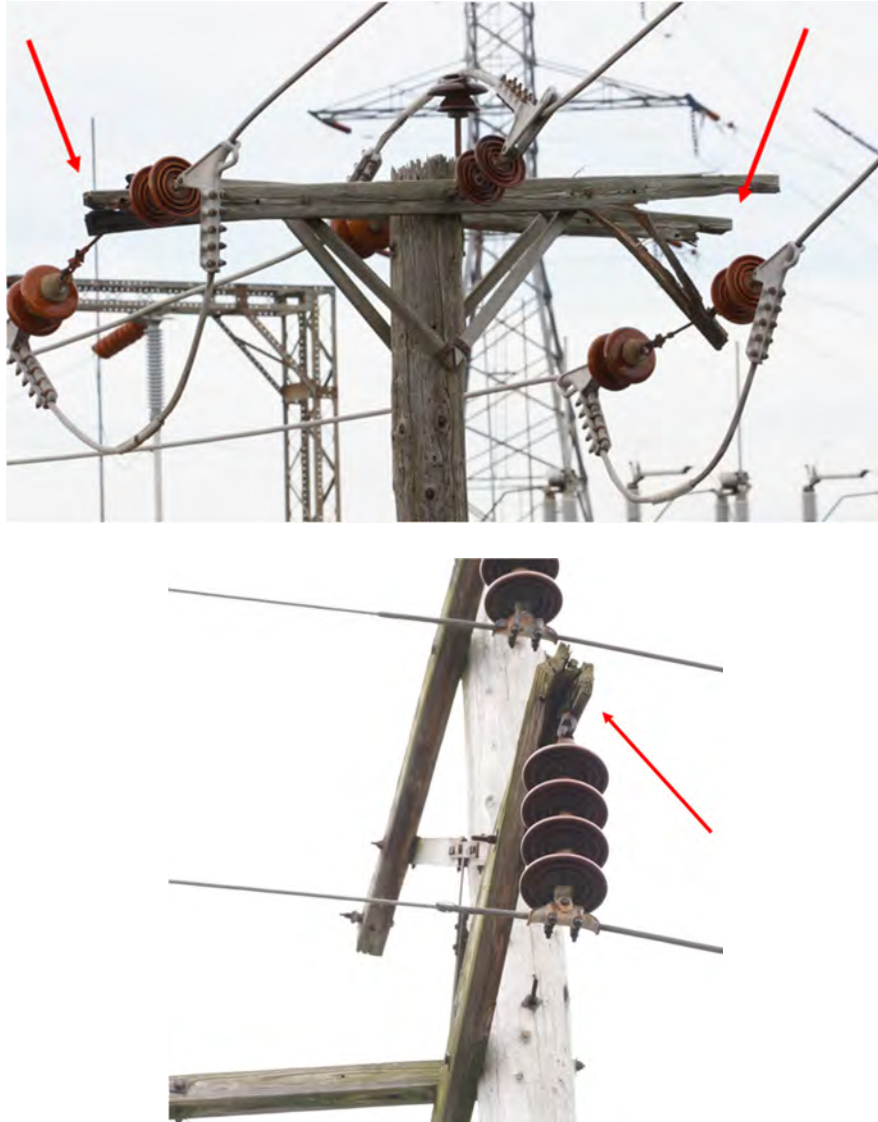
15 A. For HVD Lines, the Company determines work needs based on real-time HVD line
16 component failures or very short-term imminent failures. The Company immediately
17 responds to component failures resulting in customer outages identified from calls from
18 customers, third parties, or by alarms from the SCADA system. Once notified, system
19 operators and/or crews are quickly dispatched to locate the electric fault and restore power
20 to customers. Data from digital relays and line sensors can often be used to pinpoint the
21 location of the fault allowing crews to find the location faster.

22 Component failures that do not cause a line to trip, but decrease the integrity of the
23 line, are addressed within weeks or months once discovered. These anomalies are identified

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1 through routine annual helicopter patrols, biannual ground patrols, or through calls from
2 customers, employees, or third parties. Examples include floating phases (when a phase
3 wire becomes unsecured from an insulator), broken insulators, broken crossarms, broken
4 poles, or broken static wires. Figure 61 below provides two examples of Priority 1
5 anomalies identified during helicopter inspections.

FIGURE 61

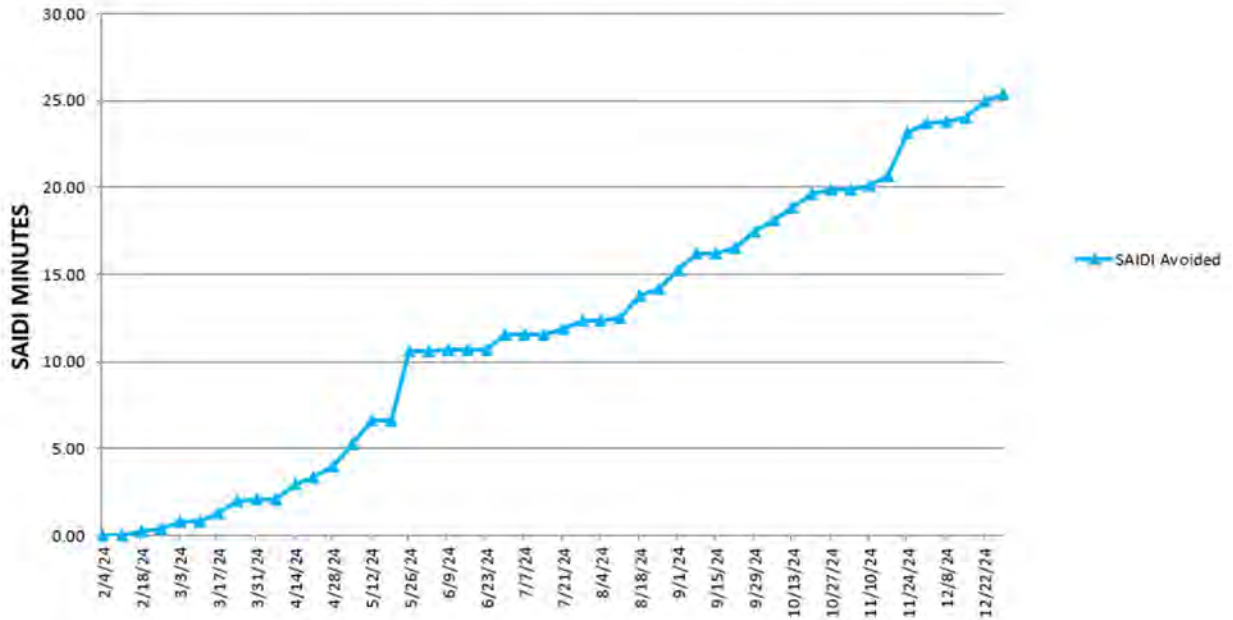


6 In 2024, the identification and correction of Priority 1 and 2 anomalies like the ones
7 shown above, before those anomalies resulted in customer outages, avoided an estimated

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25.3 SAIDI minutes. Figure 62 below shows the timeline in which failures are identified and corrected. The failures are assigned a projected SAIDI minute benefit that is realized after the correction has been made.

FIGURE 62
SAIDI avoided through correction of defects



For HVD Substations, the Company acts based on real-time failures, anomalies, and issues discovered through an annual inspection process. If an HVD substation equipment anomaly is causing an outage to customers or if its potential failure poses an immediate and intolerable electric system operating condition, it will be addressed immediately. If the equipment anomaly is not currently causing a customer outage, it will be addressed at a future point in time through the HVD Lines and Substation Rehabilitation sub-program or alternatively through the Reliability Program. Some projects, such as HVD transformer replacements with longer lead times, may be delayed if other replacements are identified that have a higher risk of failure or have failed in service.

1 **Q. Why is the Company requesting approval for these expenditures in this proceeding?**

2 A. Failure to repair faults that result in customer outages in a timely manner inhibits the
3 Company's obligation to serve. Failure to address failed equipment that does not result in
4 customer outages increases the risk of customer outages in the future if not addressed in a
5 timely manner. The spending in this sub-program maintains customer reliability or in the
6 event of a fault, restores customers quickly and safely.

7 **Q. What are the Company's projected bridge period and test year spending levels, for**
8 **which it is requesting cost recovery, in the HVD Lines and Substations Demand**
9 **Failures sub-program?**

10 A. For the bridge period, the Company is projecting HVD Lines and Substations Demand
11 Failures capital expenditures of \$8,296,000, as shown in Exhibit A-113 (MPK-3), line 33,
12 column (k). For the test year, the Company is projecting HVD Lines and Substations
13 Demand Failures capital expenditures of \$10,000,000, as shown in Exhibit A-113 (MPK-3),
14 line 33, column (l). The bridge period and test year spending by investment category is
15 broken down in Figure 63 below. Individual HVD substation failure projects can range
16 widely in scope and cost, from small transformer replacements costing \$12,000 up to large
17 transformer replacements costing \$2,000,000. This variation makes it impractical to project
18 a unit total. Projected spending on HVD substation failure projects is based on historical
19 actual spending without respect to units.

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FIGURE 63
HVD LINES AND SUBSTATION DEMAND FAILURES INVESTMENT CATEGORY
EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Pole replacements	\$2,387,470	80	\$2,877,857	97
Pole top assembly replacements	\$984,608	113	\$1,186,846	137
Switch replacements	\$735,631	6	\$886,730	7
Miscellaneous/other replacements	\$312,262	18	\$376,400	22
HVD substation failure projects	\$3,876,030	n/a	\$4,672,167	n/a
Total	\$8,296,000		\$10,000,000	

1 **Q. How did the Company develop its projected expenditures in this sub-program?**

2 A. The spending forecast is based on the historical five-year average for this sub-program.
3 Investment for this sub-program has increased in the last three years compared to the
4 previous two years. In 2022, a failed cap switcher at the Litchfield substation cost \$600,000;
5 and the beginning of a failed transformer replacement project at the Halsey substation cost
6 \$1.2 million. Both of these contributed to higher spending. In 2023, the transformer
7 replacement at the Halsey substation was completed, totaling an additional \$700,000; and
8 major transformer replacements at the Wackerly substation for \$1.4 million and the Beaver
9 Creek substation for \$2.3 million accounted for the increased spending in this investment
10 category. In 2024, a failed circuit breaker at Verona substation and resulting damage to
11 adjacent equipment increased spending in this category by \$1 million.

12 **Q. What has been the historical actual spending in the HVD Lines and Substations**
13 **Demand Failures sub-program for the past five years?**

14 A. The Company's historical actual spending in the HVD Lines and Substations Demand
15 Failures sub-program for the past five calendar years is shown below in Figure 64.

FIGURE 64

HVD LINES AND SUBSTATIONS DEMAND FAILURES HISTORIC EXPENDITURES (\$000)

2020	2021	2022	2023	2024	5-Year Average
\$6,782	\$6,050	\$10,015	\$13,524	\$11,705	\$9,615

1 **Q. What are the historical unit costs for each of the HVD Lines and Substations Demand**
2 **Failures investment categories?**

3 A. Historical unit costs for each lines-related investment category are identified in Figure 65
4 below.

FIGURE 65

HVD LINES AND SUBSTATIONS DEMAND FAILURES HISTORIC EXPENDITURES

Investment Categories	2020	2021	2022	2023	2024
Pole replacements	\$29,200 /project	\$18,800 /project	\$33,100 /project	\$30,465 /project	\$45,714 /project
Pole top assembly replacements	\$18,200/ project	\$8,300/ project	\$10,302/ project	\$10,052/p roject	\$9,707/ project
Switch replacements	\$99,500 /project	\$132,600 /project	\$143,000 /project	\$114,875 /project	\$169,950 /project
Miscellaneous other replacements	\$11,500 /project	\$37,300 /project	\$4,750 /project	\$3,187 /project	\$11,931 /project

5 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
6 **sub-program?**

7 A. Yes, with the exception of the miscellaneous other replacements investment category. Since
8 the miscellaneous/other replacements investment category encompasses a wide variety of
9 projects, the unit costs in that category show wide variation. It is possible to see variation
10 in other investment categories, as accessibility and specific equipment factors can create
11 increases in individual project costs.

4. LVD SUBSTATIONS DEMAND FAILIURES

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Substations Demand Failures sub-program.

A. The LVD Substations Demand Failures sub-program supports capital repair or replacement of failed LVD substation equipment to restore customer service and maintain reliability of electrical service. Work in the LVD Substations Demand Failures sub-program is planned and executed when an event has occurred. LVD Substations Demand Failures projects are divided into four investment categories:

- (i) regulators;
- (ii) reclosers;
- (iii) transformers; and
- (iv) other equipment.

Q. What has been the average failure population of the three main LVD substation components in the past five years?

A. Based on the five-year average from 2020 through 2024, the Company has experienced approximately four LVD substation transformer failures (approximately 0.38% of population); 43 recloser failures (approximately 0.84% of population); and 64 regulator failures (approximately 1.25% of population) per year. These historical failure rates are used to project investment needs going forward in this sub-program.

Q. What benefits will customers realize through the Company completing work in the LVD Substations Demand Failures sub-program?

A. The projected test year amount provides for the level of investment necessary in LVD Substations Demand Failures to support capital repair or replacement of failed LVD substation equipment to address interruptions, maintain service quality, and meet the

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1 Company's obligation to serve customers. Absent investment in this category, customers
2 would remain without electric service or experience unacceptable service quality when
3 substation equipment fails. For example, if a substation transformer serving
4 5,000 customers failed, electric service to those customers would not return until the
5 substation transformer was replaced or a mobile substation was temporarily installed. If a
6 substation regulator serving 1,000 customers failed and was not replaced, those customers
7 could eventually experience electrical equipment damage or electrical equipment may not
8 function properly due to inadequate service voltage.

9 **Q. Why is the Company requesting approval of these expenditures in this proceeding?**

10 A. The work in this sub-program is essential to restoring interrupted electrical service to
11 customers or to restore the safe and reliable operation of the substation.

12 **Q. What are the Company's projected bridge period and test year spending levels, for**
13 **which it is requesting cost recovery, in the LVD Substations Demand Failures**
14 **sub-program?**

15 A. For the bridge period, the Company is projecting LVD Substations Demand Failures capital
16 expenditures of \$11,923,000, as shown in Exhibit A-113 (MPK-3), line 34, column (k). For
17 the test year, the Company is projecting LVD Substations Demand Failures capital
18 expenditures of \$8,961,000, as shown in Exhibit A-113 (MPK-3), line 34, column (l). The
19 Company's historical actual spending in the LVD Substations Demand Failures
20 sub-program, along with the bridge period and test year projections, are shown in Exhibit
21 A-113 (MPK-3), line 34.

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1 **Q. How did the Company develop its projected expenditures in this sub-program?**

2 A. The Company's requested spending levels for the bridge period and test year are based on
3 projected failure rates, which are in turn based on historical failure rates as defined above.
4 The projected bridge period and test year capital expenditures were determined by
5 evaluation of the 2020 through 2024 actual spend and based on projected future costs.

6 **Q. Please explain how the capital expenditures projected for the bridge period and the**
7 **test year for this sub-program will be allocated across the four investment categories.**

8 A. The Company is projecting unit and capital expenditures in the bridge and test years for
9 each investment category as identified in Figure 66, based on the Company's average failure
10 rates over the historical period of 2020 through 2024.

FIGURE 66
LVD SUBSTATIONS DEMAND FAILURES INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test year # of Units
Regulators	\$5,280,000	80	\$3,960,000	60
Reclosers	\$1,200,000	48	\$900,000	36
Transformers	\$3,380,000	4	\$3,380,000	4
Other Equipment	\$2,063,000	41	\$721,000	14
Total	\$11,923,000	173	\$8,961,000	114

11 **Q. Please explain the year-over-year variation in spending in this sub-program.**

12 A. In 2021, the Company replaced two transformers that failed in 2020 but were replaced in
13 2021. Baum Street and Dewey Substations both have two transformers, so when one of the
14 transformers failed at each substation in 2020, electric service was restored by temporarily
15 transferring the impacted customers to the other transformer until the failed transformer
16 replacement projects were completed in 2021. In 2023, six emergent projects contributed

1 to the majority of spending within the Other Equipment Replacements investment category.
2 All six projects required mobile substations and three of those projects required substation
3 structure modifications resulting in a higher project cost. In 2024, the Company replaced
4 30 more regulators than were originally forecasted, replaced 14 more reclosers than were
5 originally forecasted, and 12 emergent projects contributed to the majority of spending
6 within the Other Equipment Replacements investment category. The 12 emergent projects
7 consisted of various equipment failures such as transformer bushings, transformer cooling
8 fans, substation switches, and lightning arresters.

9 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
10 **sub-program?**

11 A. Unit costs are generally a reasonable reflection of the expected project spending for the
12 regulator, recloser, and transformer investment categories. Unit cost is not a good measure
13 to project spend for the Other Equipment investment category due to varying work scopes
14 that are generally required for each project.

15 **5. METRO DEMAND FAILURES**

16 **Q. Please explain what capital projects, activities, and other types of work will be enabled**
17 **by expenditures in the Metro Demand Failures sub-program.**

18 A. The Metro Demand Failures sub-program involves the replacement of failed cables,
19 transformers, and civil infrastructure within the Company's Metro systems. Metro Demand
20 Failures costs are highly dependent on the type of asset that fails. Civil assets such as
21 manholes, vaults, and duct banks are highly labor intensive with correspondingly high
22 restoration costs. Electrical asset failures are variable, as spare components (i.e.
23 transformers and switches) are kept in local storerooms and can be replaced immediately.
24 Primary cables are kept in storerooms and may be immediately replaced or replaced at a

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1 later date given its loop or primary selective design. Secondary and service cables are
2 designed in a radial nature, so secondary and service failures are immediately replaced to
3 restore service.

4 The Company projects its needed investment level in this sub-program based on
5 historical averages and trends. In this filing, spending in Metro Demand Failures is divided
6 into three investment categories:

- 7 (i) Cable Failure and Replacement;
- 8 (ii) Transformer Failure and Replacement; and
- 9 (iii) Civil Infrastructure Failure and Replacement.

10 **Q. Why does the Company perform replacement of electrical assets in this sub-program?**

11 A. Electrical assets in Metro vaults may fail due to age, deterioration, standing water, and
12 runoff contaminants (e.g. salt). The most common electrical assets that fail are Metro
13 transformers, primary cable, and secondary cable. If a primary cable fails, the Company
14 identifies potential switching schemes to immediately restore service to customers. After
15 the fault is isolated and customers are restored, there are times when the Metro system is no
16 longer in a loop or primary selective configuration (i.e. it no longer has feeds from multiple
17 directions) and must be repaired. A design will be created for permanent repairs. By leaving
18 this faulted section isolated for a long period of time, there would no longer be a way to
19 restore service to customers from that direction. If a transformer fails, it is replaced with a
20 spare unit. If a secondary cable fails, a new cable is pulled in a spare conduit adjacent to
21 the failed cable. The failed cable is cut at both ends and removed, creating another spare
22 conduit.

1 **Q. What are the general factors that contribute to the need for investment in the Metro**
2 **Demand Failures sub-program?**

3 A. Many factors contribute to deterioration of the cabling, equipment, and civil infrastructure
4 in the Metro systems, including age of the system and public damage. The Company
5 commonly sees several specific problems caused by deteriorating electrical equipment
6 including:

- 7 • primary cable failures;
- 8 • transformer and other electrical equipment failures; and
- 9 • secondary and services failures.

10 The Company commonly experiences public damage related failures resulting from:

- 11 • Work performed in the ROW without notification to the MISS DIG system;
- 12 • Improper directional boring techniques used by contractors performing work for
13 other utilities in the ROW; and
- 14 • New business and redevelopment engineered plans, including parts of the ROW,
15 with poor surveying and notification to the Company.

16 **Q. What benefits will customers realize through the Company completing work in the**
17 **Metro Demand Failures sub-program?**

18 A. Absent investment in this category, customers would remain without electric service or the
19 redundant portion of the metro system would remain out of service indefinitely. Leaving
20 the redundant portion of the system out of service would eliminate the availability to
21 complete restoration of other unplanned events. The projected bridge period and test year
22 amounts provide for the level of investment in Metro Demand Failures needed to support
23 capital repair or replacement of failed metro equipment to address interruptions, and to meet
24 the Company's obligation to serve customers.

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1 **Q. Why is the Company requesting approval of these expenditures in this proceeding?**

2 A. The work in this sub-program is essential to restore interrupted electrical service to
3 customers served by the metro underground system or to make immediate repairs to the
4 civil infrastructure to protect the public.

5 **Q. What are the Company's projected bridge period and test year spending levels, for**
6 **which it is requesting cost recovery in the Metro Demand Failures sub-program?**

7 A. The Company is projecting capital expenditures of \$664,000 in the bridge period, as shown
8 in Exhibit A-113 (MPK-3), line 36, column (k), and \$350,000 in the test year, as shown in
9 Exhibit A-113 (MPK-3), line 36, column (l). The Company's historical actual spending in
10 the Metro Demand Failures sub-program, along with the bridge period and test year
11 forecasts, are shown in Exhibit A-113 (MPK-3), line 36.

12 **Q. How did the Company develop its projected expenditures in this sub-program?**

13 A. The Company's projected bridge period and test year spending are based on a continuation
14 of recent spending levels since 2021, after the re-categorization of imminent failure work to
15 the Metro Rehabilitation sub-program.

16 **Q. Please explain the year-over-year variation in spending in this sub-program.**

17 A. Before 2020, the Company invested more than average in this sub-program to address
18 imminent failure issues with civil and electrical infrastructure in the Flint and Jackson Metro
19 systems. Today, that work would be addressed in the Metro Rehabilitation sub-program.
20 This rehabilitation work has reduced the cost of failures in the Metro system. Beginning in
21 2021, the Company experienced fewer actual failures requiring equipment replacement,
22 resulting in lower than average spending due to rehabilitation and reliability investments.

1 **Q. Does an average unit cost accurately reflect the expected spending per project for this**
2 **sub-program?**

3 A. No. Average unit cost is not a good measure of spending to predict the cost of an individual
4 project in this sub-program because of the variance in work required to address failures,
5 which range from \$4,500 to \$60,000 per project. Additionally, the number of units
6 completed each year is small, which inhibits reliable unit cost metrics.

7 **6. HVD ASSET RELOCATIONS**

8 **Q. What is the purpose of the HVD Asset Relocations sub-program?**

9 A. The overall Asset Relocations Program includes capital investments to relocate assets, as
10 described by Company witness Kelly in his direct testimony. The HVD Asset Relocations
11 sub-program includes the capital investments to relocate 46 kV and 138 kV lines on a
12 reactive basis.

13 **Q. Please explain what projects, activities, and other types of work will be enabled by**
14 **expenditures in the HVD Asset Relocations sub-program.**

15 A. The HVD Asset Relocations sub-program includes the capital investments necessary to
16 facilitate non-reimbursable relocations of 46 kV and 138 kV lines required to accommodate
17 usage of public ROW and required transmission project work. The cost of relocating lines
18 in the road ROW, or in some instances on private property, is typically the responsibility of
19 the Company. In other cases, such as relocation work requested by businesses and
20 residential customers, the requesting party will pre-pay or reimburse the Company for the
21 cost of the relocation, but the transactions will still pass through this sub-program.

1 **Q. Which parties typically request HVD Asset Relocations projects?**

2 A. There are four general categories of parties that may request HVD Asset Relocations
3 projects: municipalities and other government agencies, transmission owners, private
4 landowners, and internal Company departments.

5 **Q. Please explain each category of parties that may request HVD Asset Relocations.**

6 A. Municipalities and other government agencies (including the Michigan Department of
7 Transportation (“MDOT”)) request HVD Asset Relocations to facilitate their civil
8 engineering projects, such as road and bridge widening and improvements, repairs to
9 municipal facilities, work on water and sewer lines, municipal building and structure
10 construction projects, and streetlight and traffic signal modifications. The HVD Asset
11 Relocations allow those agencies to safely access their facilities without having to work
12 around HVD infrastructure. Relocations may be temporary or permanent.

13 METC or another transmission owner may request HVD Asset Relocations to
14 accommodate their transmission projects. For example, the Company may have HVD lines
15 attached to METC structures below transmission lines. Depending on the nature of the
16 project, METC may reimburse the Company for associated costs on a case-by-case basis.

17 Private landowners and businesses request HVD Asset Relocations to accommodate
18 additions, landscaping, and other construction projects on their property. One relatively
19 common request is for overhead lines to be repositioned to allow for building additions.

20 Internal Company departments may require HVD Asset Relocations to
21 accommodate their own projects they are planning, such as a 2022 project requested by the
22 HVD Planning Department on the National City, Prescott, and Whitestone Point Lines,

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where poles were relocated to facilitate the rebuild of the HVD Arenac Substation that is currently underway.

Q. What are some examples of recent HVD Asset Relocations projects?

A. In 2021, the Company relocated four structures on the Grand Valley 46 kV Line in Kent County to accommodate a project by the Kent County Road Commission. The Company also relocated the Millers Point 138 kV line to support MDOT's work to rebuild US-131/KL Avenue bridge in Kalamazoo County in 2023. These examples and others are shown in Figure 67 below.

FIGURE 67
HVD ASSET RELOCATIONS RECENT EXAMPLES

Project Name	Order Created/ Work Completed	Net Capital
Virgina Park Line Relocate Structure 159-166. Requested by Customer.	3/1/2023 – 5/1/2024	\$ 237,890
Millers Point 138 kV line. Relocate line to support MDOT rebuild of US-131/KL Ave Bridge. Requested by MDOT.	6/28/18 – 10/02/2023	\$ 4,481,153
Upton Line. Relocate Structures 193-199. Requested by customer.	9/9/2021 – 8/19/2022	\$ 545,700
Ramona Line. Relocate structures for new I-96 on ramp. Requested by MDOT.	4/13/2021 – 4/15/2022	\$ 581,400
Okemos Line. Relocate Structures 1167 and 1168 due to Okemos Road project. Requested by Ingham County Road Commission.	9/26/2020 - 7/14/2022	\$ 477,900

Q. How does the Company identify HVD Asset Relocations projects?

A. As discussed above, projects are typically identified by four general categories of parties that may request HVD Asset Relocations projects: municipalities and other government agencies, transmission owners, private landowners, and internal Company departments.

1 **Q. Did the Company consider any alternative approaches for these investments?**

2 A. When an asset must be relocated in this sub-program, there is generally no alternative to
3 doing so. However, each project in this sub-program is evaluated by the HVD Lines
4 Engineering group for the best method of achieving the customer's objective (typically to
5 move the line out of the way of something that will be built in that space), at the lowest cost
6 alternative.

7 **Q. What are the Company's projected bridge period and test year spending levels, for
8 which it is requesting cost recovery, in the HVD Asset Relocations sub-program?**

9 A. The Company is projecting HVD Asset Relocations capital expenditures of \$1,197,000 in
10 the bridge period, and \$899,000 in the test year, as shown in Exhibit A-118 (MPK-8), line 2.

11 **Q. How did the Company develop its projected expenditures in this sub-program?**

12 A. The Commission approved test year spending of \$900,000 in Case No. U-21585. The
13 projected bridge period and test year spending in this case is aligned with this approved
14 amount, and it is also closely aligned with actual spending in 2024. In the absence of any
15 pre-identified significant projects in this case for this sub-program, Consumers Energy is
16 projecting to hold investment flat in this sub-program.

17 **Q. What benefits will customers realize through the Company completing work in the
18 HVD Asset Relocations sub-program?**

19 A. The primary purpose of this sub-program is to relocate existing HVD lines at the request of
20 customers, and to fulfill the needs of customers and other external parties, which the
21 Company is required to do. This sub-program also helps improve reliability through the
22 installation of new equipment that meets the Company's current design standards.

1 **Q. Are there any projects that span multiple years?**

2 A. Yes. Since most projects take several months to design and construct, it is common for
3 projects to span from one year into another (see the examples of projects in Figure 67 earlier
4 in this section).

5 **Q. What are the historical costs in this sub-program over the past five years?**

6 A. The historical costs in this sub-program are shown in Figure 68 below.

FIGURE 68
HVD ASSET RELOCATIONS HISTORICAL SPENDING

2020	2021	2022	2023	2024	5-Year Average
\$1,906,000	\$1,709,000	\$2,565,000	\$5,319,000	\$845,000	\$2,469,000

7 **Q. Are any of the costs in the five historical years a significant outlier in this**
8 **sub-program?**

9 A. In 2023, significant spending occurred as a result of ongoing work to relocate multiple HVD
10 lines for MDOT, with those large projects totaling \$4,397,000.

11 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
12 **sub-program?**

13 A. No. Most projects in this category are customer requested and customer funded. A typical
14 project will be paid for and completed in the same year, resulting in a net-zero spend. Some
15 projects span multiple years, resulting in a credit one year for work performed in another.
16 The remaining projects are those where HVD lines are in the public ROW for which the
17 Company is obligated to cover the cost. There are typically only a few of these projects,
18 but they do range in cost from the single pole relocation for \$20,000 to projects like the

1 current US-131/KL Avenue Bridge rebuild requested by MDOT, for over \$4 million. As a
2 result, an average unit cost is not a useful or insightful cost measure in this sub-program.

3 **7. METRO ASSET RELOCATIONS**

4 **Q. Please explain what projects, activities, and other types of work will be enabled by the**
5 **expenditures in the Metro Asset Relocations sub-program.**

6 A. The Metro Asset Relocations sub-program responds to both internal and external requests
7 to relocate or modify civil structures, such as manhole chimneys and castings due to road
8 grade changes, either in a public ROW or on private property, and underground or
9 padmounted electric facilities and service points not related to a new business request. The
10 Company's Metro relocation projects can be on a demand basis or a planned and
11 coordinated basis, with the Company making it a priority to meet mutually agreed upon
12 deadlines and milestones, and to perform the required work within the requested ROW.
13 Projects requested by other departments within the Company may be planned further in
14 advance, rather than on a demand basis.

15 **Q. What is the typical nature of external relocation requests in the Metro Asset**
16 **Relocations sub-program?**

17 A. External relocation requests come from state agencies, municipalities, downtown
18 development authorities, and private developers. State agencies and municipalities may
19 request relocations to accommodate for upcoming civic improvement work for a specific
20 ROW. Typical improvements include storm and sanitary sewers, water mains, street
21 improvements, and streetscapes. Municipalities, downtown development authorities, and
22 private developers may request relocations to convert overhead electric systems to
23 underground civil and electrical systems, generally to improve aesthetics. These requests
24 typically require the customer to provide a non-refundable engineering deposit for the

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1 Company to perform a feasibility study to find an underground path for the civil
2 infrastructure system.

3 **Q. Does the Company request reimbursement for a Metro relocation request?**

4 A. Yes, the Company seeks reimbursement for a third-party initiated Metro relocation request
5 on a case-by-case basis. Commonly, reimbursement is sought when a third party requests
6 the existing overhead distribution system be converted to underground. The same process
7 applies to those third parties requesting a vacation of the ROW—the Company will seek
8 reimbursement to convert existing overhead distribution to underground distribution, and
9 seek a permanent easement from the new property owners of the vacated ROW.

10 **Q. Does reimbursement match the cost of relocation?**

11 A. Yes, when the Company establishes reconcilable contracts with the requesting third party,
12 the Company will either credit or invoice the requesting party at the end of the project for
13 its actual costs for the conversion of overhead distribution to underground metro
14 distribution.

15 **Q. What is an example of a recent externally requested Metro Asset Relocations project?**

16 A. The Company and the City of Saginaw are engaged in a two-year coordination of utilities
17 agreement allowing the Company to expand its metro facilities in the Water Street ROW.
18 The project is in coordination with the City of Saginaw and Saginaw Future to make the site
19 ready for the planned Saginaw Medical Diamond development. The Saginaw Medical
20 Diamond will include medical offices and education, mixed use residential, and retail.

21 At the request of the City of Kalamazoo, the Company delayed the start of its
22 coordination of utilities project, to rebuild its metro facilities in the Kalamazoo Avenue
23 ROW to 2026. This project is the first of many the City of Kalamazoo Public Works

1 department has identified to transform its one-way street network back to two-way traffic
2 flows in Downtown Kalamazoo.² The City is presently in preliminary design for its
3 Michigan Avenue street conversion, in which Consumers Energy will also seek to rebuild
4 its aging infrastructure in a coordination of utilities fashion with engineering starting in
5 2026.

6 **Q. What is the Company's process for planning Metro Asset Relocations projects in**
7 **response to internal requests?**

8 A. Projects triggered by an internal request are considered during the Metro planning process,
9 which takes place in July and August of each year. Company engineering planners, with
10 responsibility for planning and design of the affected Metro system area, prepare scope
11 documents and estimated project costs during this process. Internal requests are triggered
12 by various workgroups, such as Substation Planning, LVD Planning, or HVD Planning. An
13 example of an internal request is in Jackson, where Substation Planning plans to replace the
14 Ingham Substation transformer bank (refer to Exhibit A-109 (MLH-3), page 5, line 14).
15 Metro will support this project by converting its electrical vaults from delta operations to
16 grounded wye and reconfigure the primary circuits for better substation loading and
17 performance.

18 **Q. What benefits will customers realize through the Company completing work in the**
19 **Metro Asset Relocations sub-program?**

20 A. Although the primary purpose of this sub-program is to accommodate the needs of
21 customers and other external parties, the sub-program does help improve reliability through
22 the installation of new equipment. When the Company replaces old or obsolete equipment

² <https://www.kalamazoocity.org/News-articles/Kalamazoo-Avenue-Two-Way-Plans-will-be-Introduced-at-May-Meetings>

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1 with new equipment as part of a relocation project, reliability is improved since the new
2 equipment has up-to-date design standards and less general wear and tear. Customers
3 connected directly to these assets receive these reliability benefits.

4 **Q. Please identify the projects that will be accomplished with the requested spending level**
5 **in the Metro Asset Relocations sub-program.**

6 A. The Company has identified projects for the bridge period, listed in Exhibit A-109 (MLH-3),
7 page 13, and for the test year, listed in Exhibit A-110 (MLH-4), page 13. Projected project
8 costs were determined based on the specific work scope for each project and historical costs
9 from similar projects. These exhibits also identify the location of the projects.

10 **Q. What are the Company's projected bridge period and test year spending levels, for**
11 **which it is requesting cost recovery, in the Metro Asset Relocations sub-program?**

12 A. The Company is projecting Metro Asset Relocations capital expenditures of \$16,094,000 in
13 the bridge period, as shown in Exhibit A-113 (MPK-3), line 40, column (k), and
14 \$20,405,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 40, column (l). The
15 Company's historical actual spending in the Metro Asset Relocations sub-program, along
16 with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3),
17 line 40.

18 **Q. What is driving the Company's projected increase in investment in Metro**
19 **Relocations?**

20 A. The Company's spending in the Metro Asset Relocations sub-program is based on external
21 requests, and therefore varies from year to year based on the requests that the Company
22 receives. In the instant case, the Company is addressing more requests than in recent years,
23 tied to municipal projects in Grand Rapids, Saginaw, and Kalamazoo. The associated

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1 identified Metro Relocations projects determine the amount of investment needed for this
2 sub-program.

3 **Q. How did the Company develop its projected bridge period expenditures?**

4 A. The Company has identified relocation projects in Exhibit A-109 (MLH-3), page 13, that
5 supports the bridge period spending level, and projected expenditures are based on these
6 projects.

7 **Q. How did the Company develop its projected test year expenditures?**

8 A. The spending amount for the test year is supported based on three municipal projects
9 planned for 2026 and early 2027, each of which require Metro Relocations work.

10 First, Kalamazoo Avenue in the City of Kalamazoo will be reworked, and the
11 Company will coordinate with the City's engineering department. The Company will be
12 installing new Metro infrastructure to replace its aging system within the ROW, and provide
13 service to new Company-owned streetlighting and traffic signal services to new city traffic
14 signals at various intersections.

15 The second project is the Front Avenue ROW modifications in the City of Grand
16 Rapids. The Company is replacing its Metro assets along Front Avenue in coordination
17 with ROW modifications by the City of Grand Rapids for the Grand Rapids Public Museum
18 expansion, a Grand Valley State University project, and modification of pedestrian flow in
19 the area.

20 The third project is an internal request to accommodate a large duct bank for the
21 future Quicksilver LVD substation located on Wealthy Street west of Front Avenue (refer
22 to Exhibit A-110 (MLH-4), page 10, line 8. This duct bank and substation will support the
23 growth and development in and around the Acrisure Amphitheater, Amway Soccer

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1 Stadium, and Grand Valley State University's Blue Dot project and long range facilities
2 plan for the Pew Campus expansion.

3 **Q. Are there any projects that span multiple years?**

4 A. Yes, due to the size and scope of some Metro Asset Relocation projects, it is common for
5 the civil assets to be installed in one year with the electrical assets installed in the year
6 following. The Kalamazoo Avenue project, listed in Exhibit A-110 (MLH-4), page 13,
7 lines 7 and 8, is a multi-phase project in which construction will span from 2026 to 2027.
8 The Quicksilver substation duct bank support project will also span a number of years.
9 These project timelines may be adjusted if future construction or permit barriers are
10 experienced.

11 **Q. Please explain the year-over-year variation in spending in this sub-program.**

12 A. Investment in this sub-program depends heavily on the volume and complexity requests for
13 relocation. Most recent years have set new levels of investment. Continued growth in these
14 metro areas are expected to sustain a need for higher-than-average capital expenditures in
15 this sub-program.

16 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
17 **sub-program?**

18 A. No. Average unit cost is not a good measure of spending to predict the cost of an individual
19 project in this sub-program. There is a wide variance of scale and scope among the work
20 required.

VII. LINE CATEGORIZATION

Q. Please discuss Exhibit A-111 (MLH-5).

A. Exhibit A-111 (MLH-5) documents how the Company categorized substation and HVD line distribution assets for the EAC report. The EAC report utilized by COSS to break out certain distribution assets and related costs into greater detail.

Q. How were substation assets categorized in the EAC report?

A. The Company's engineering personnel reviewed substation drawings and engineering records to assign substation assets to each EAC report category. The substation categories in the EAC report, listed below, capture both the high side asset voltage (138 kV or 69-46kV) and the voltage level of downstream facilities (either V1, V2, V3 and/or V4)³ connected to/relying on that substation:

- 138 kV (V1) Bulk Power Substations (Shared: V2,3,4)
- 138 kV (V1) Distribution Substations (Shared: V3,4)
- 138 kV (V1) Substations (V1 Only)
- 69-46 kV (V2) Bulk Power Substations (Shared: V2,3,4)
- 69-46 kV (V2) Distribution Substations (Shared: V3,4)
- 69-46 kV (V2) Substations (V2 Only)
- GSU Substations (Production)
- Other Equipment and Facilities

Substations that serve generation were categorized as GSU or Generation Step Up. Substations serving a single, dedicated customer were categorized as either 138 kV or 69-46 kV V1 or V2 Only depending on the customer's voltage level. Substations serving multiple customers through primary distribution (e.g. distribution substations) were

³ Where V1: $138 \geq X > 120$; V2: $120 \geq X > 25$; V3: $25 \geq X > 2.4$ and V4: 2.4 kV or less.

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1 categorized as either 138 kV or 69-46 kV “Shared: V3, V4” as appropriate. Where a
2 substation serves multiple categories, the Company calculated the appropriate weighting by
3 reviewing and categorizing the major assets within the substation, focusing on major
4 equipment including transformers, voltage regulators, breakers, and bulk capacitors. For
5 example, if a substation contains a transformer that serves a single, dedicated customer (V2)
6 and a second transformer that serves only primary distribution, that substation is 50% V2
7 and 50% V3, V4. Or, if a substation contains a 138 kV breaker (V2), a 138/46 kV
8 transformer (V2), two 46 kV breakers (V2), and a 46 kV/Distribution transformer (V3, V4)
9 that substation is 20% V3, V4 and 80% V2.

10 **Q. How were HVD line assets categorized in the EAC report?**

11 A. The Company’s engineering personnel reviewed the HVD lines and assigned them to the
12 EAC report categories. The EAC report categories, listed below, capture the line type
13 (overhead or underground), energized voltage level (138 kV or 69-46 kV) and the voltage
14 of downstream facilities (either V1, V2, V3 and/or V4) connected to/relying on that line.

15 Overhead (“OH”) Lines:

- 16 o 138 kV (V1) OH Lines (Shared: V1, 3, 4)
- 17 o 138 kV (V1) OH Lines (Shared: V3, 4)
- 18 o 138 kV (V1) OH Lines (V1 Only)
- 19 o 69-46 kV (V2) OH Lines (Shared: V2, 3, 4)
- 20 o 69-46 kV (V2) OH Lines (Shared: V3, 4)
- 21 o 69-46 kV (V2) OH Lines (V2 Only)
- 22 o GSU OH Lines (Production)
- 23 o Other Equipment and Facilities

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Underground (“UG”) Lines:

- o 138 kV (V1) UG Lines (V1 Only)
- o 69-46 kV (V2) UG Lines (Shared: V2, 3, 4)
- o 69-46 kV (V2) UG Lines (Shared: V3, 4)
- o 69-46 kV (V2) UG Lines (V2 Only)
- o GSU UG Lines (Production)
- o Other Equipment and Facilities

Lines that serve only a generation substation were categorized as OH or UG GSU or Generation Step Up. Lines serving only a dedicated customer substation were reviewed and categorized according to the asset type (OH or UG), energized voltage level, and included as either V1 or V2 Only depending on the dedicated customer’s voltage level. Lines serving only a distribution substation were categorized as Shared:V3, V4. If the line serves multiple generation, dedicated customer, and/or distribution substations, the common section of the line was categorized as shared between the voltage categories of the downstream substations served from that section of the line.

For example, a line section directly connected to the source transmission line, down to the first junction point where it branches off to serve multiple substations is categorized as “V1, V3, V4” or “V2, V3, V4” based on the line voltage and the category of substations connected to it. From the junction point, if a generation substation is connected at the end of that line section, that section of line is categorized as Generation; if a dedicated customer substation is connected at the end of that line section, that section of line is categorized as V1 or V2; and if a distribution substation is connected at the end of that line section, that section of line is categorized as “V3, V4”.

To give another example, in the case where the line section is directly connected to the source 46 kV line, the line section up to the first junction point where it branches off to serve the substation, is categorized as “V2, V3, V4” based on the line voltage. From the junction point, if a generation substation is connected at the end of that line section, that section of line is categorized as Generation; if a dedicated customer substation is connected at the end of that line section, that section of line is categorized as V2; and if a distribution substation is connected at the end of that line section, that section of line is categorized as “V3, V4”.

VIII. SUMMARY

Q. Please provide a brief overview of your testimony and the intent of investing in HVD capital programs to support the Company’s electric distribution system.

A. My testimony has provided an overview of the HVD system and associated capital investments to improve reliability and resiliency of the system while serving new customers to support economic development in the state of Michigan. The testimony provided detail of each HVD capital investment program, the basis of planned investments, and benefits. All HVD capital investments outlined in my testimony are identified and planned to support the overall objectives and strategy outlined in the Company’s Reliability Roadmap. My testimony highlighted increased spending in several areas in order to meet the reliability and asset health goals defined in the Reliability Roadmap.

As supported throughout my testimony, the Company’s projected HVD capital expenditures are summarized in Figure 69 and should be approved by the Commission.

FIGURE 69
HVD CAPITAL EXPENDITURE SUMMARY

	Bridge Period	Test Year
All Programs	\$524,846,000	\$417,546,000

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1 **Q. Does this complete your direct testimony?**

2 **A. Yes.**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

MICHAEL P. KELLY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MICHAEL P. KELLY
U-21870 DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

2 A. My name is Michael P. Kelly, and my business address is 1945 West Parnall Road,
3 Jackson, Michigan, 49201.

4 **Q. By whom are you employed?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

6 **Q. What is your position with Consumers Energy?**

7 A. I am currently the Executive Director of Electric Distribution Strategy.

8 **Q. What is your formal educational experience?**

9 A. In 2002, I received a Bachelor of Science in Engineering in Mechanical Engineering from
10 the University of Michigan – Ann Arbor. In 2005, I received a Master of Science in
11 Engineering in Mechanical Engineering from the University of Michigan – Dearborn. In
12 2009, I received a Master of Business Administration from the University of Michigan –
13 Ann Arbor.

14 **Q. Please describe your business experience.**

15 A. From 2002 to 2007, I was employed by Yazaki North America in Canton, Michigan, as an
16 engineer working in roles that spanned Testing and Validation and Component
17 Engineering. I left Yazaki North America in 2007 to pursue a Master of Business
18 Administration, and upon receiving my degree in 2009, I accepted a position at DTE
19 Energy Company (“DTE”) as a Financial Consultant, where I assumed roles in Financial
20 Planning and Analysis, Distribution Operations Decision Support, and Renewable Energy
21 Business Development. In 2012, I accepted a position working in DTE’s Electric Strategy
22 organization and was promoted to Manager of the team in 2014. As Manager of the
23 Electric Strategy team, I was responsible for the development of the electric utility’s annual

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1 priority plans and long-term financial planning functions. In 2017, I accepted the role of
2 Manager within DTE’s Tree Trimming organization. In this role, I was responsible for the
3 long-term and annual maintenance trimming schedules, and execution of contracts with the
4 providers of tree trimming and herbicide services. In October 2018, I accepted a position
5 as a Director, Corporate Strategy at Consumers Energy, where I was responsible for
6 helping to maintain the Company’s strategic planning process and working with customers
7 on initiatives such as the Long-Term Industrial Load Retention Rate. In June 2022,
8 I accepted my current role as Executive Director of Electric Distribution Strategy.

9 **Q. What are your responsibilities as Executive Director of Electric Distribution**
10 **Strategy?**

11 A. My responsibilities as Executive Director of Electric Distribution Strategy include
12 development of the Company’s *Electric Distribution Infrastructure Investment Plan*
13 (“EDIIP,” also referred to as the “Reliability Roadmap”) and implementing the Electric
14 Distribution department’s planned activities consistent with its financial plans.

15 **Q. Have you previously provided testimony before the Michigan Public Service**
16 **Commission (“MPSC” or the “Commission”)?**

17 A. Yes, I provided testimony in the following MPSC cases:

18	Case No. U-20697	Electric General Rate Case;
19	Case No. U-20899	Karn 1 and 2 Securitization;
20	Case No. U-21389	Electric Rate Case;
21	Case No. U-21585	Electric Rate Case; and
22	Case No. U-21918	Investment Recovery Mechanism (“IRM”).

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1 **Q. What is the purpose of your direct testimony in this proceeding?**

2 A. The purpose of my direct testimony is to provide an overview of the Company's electric
3 distribution strategy. I will begin my testimony by detailing how the Company measures
4 electric reliability performance as well as its past actual and projected future reliability
5 performance, based on the impact of the distribution investments proposed in this electric
6 rate case.

7 Next, I will explain the strategic objectives that guide the Company's investment
8 decisions to achieve reliability performance in the face of the increasingly challenging
9 weather conditions, customer technology adoption, and system deterioration. I will explain
10 the technology projects that support electric distribution as well as the Company's
11 projected electric distribution operating and maintenance ("O&M") spending.

12 Finally, I will introduce the Company's line loss study; discuss a requirement
13 related to critical inventory as ordered by the Commission in Case No. U-21585; and
14 address certain issues related to advanced metering infrastructure ("AMI").

15 **Q. Are you the only Company witness addressing the Company's electric distribution**
16 **strategy and investments?**

17 A. No. To provide comprehensive support for the Company's electric distribution requests,
18 six additional witnesses are providing evidence in this proceeding. Company witness
19 Jennifer M. Partlan will support the Company's historical and planned capital investments
20 in the Low Voltage Distribution ("LVD") and Metro systems. Company witness Megan L.
21 Hayward will support the Company's historical and planned capital investments in the
22 High Voltage Distribution ("HVD") system. Company witness Scott A. McPhail will
23 support the Company's historical and planned capital investments in the Grid Automation

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1 Program. Company witness Daniel A. Schmoekel will support the Company's historical
2 and planned capital investments in streetlighting. Company witness Sara E. Stewart will
3 support the Company's historical and planned spending for the Forestry Line Clearing
4 Program. Company witness Andrew R. Snider will support the Company's historical and
5 forecasted spending in Service Restoration.

6 **Q. Are you sponsoring any exhibits with your direct testimony?**

7 A. Yes. I am sponsoring the following exhibits:

8 Exhibit A-12 (MPK-1) Schedule B-5.7 Electric Distribution Summary of
9 Actual and Projected Capital
10 Expenditures;

11 Exhibit A-112 (MPK-2) Electric Distribution Actual and
12 Projected Capital Expenditures
13 Master;

14 Exhibit A-113 (MPK-3) Electric Distribution Summary of 5yr
15 Historical Electric Capital
16 Expenditures;

17 Exhibit A-114 (MPK-4) New Business Program Summary of
18 Actual and Projected Electric Capital
19 Expenditures;

20 Exhibit A-115 (MPK-5) Reliability Program Summary of
21 Actual and Projected Capital
22 Expenditures;

23 Exhibit A-116 (MPK-6) Capacity Program Summary of
24 Actual and Projected Capital
25 Expenditures;

26 Exhibit A-117 (MPK-7) Demand Failures Program Summary
27 of Actual and Projected Capital
28 Expenditures;

29 Exhibit A-118 (MPK-8) Asset Relocation Program Summary
30 of Actual and Projected Capital
31 Expenditures;

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1	Exhibit A-119 (MPK-9)	Electric Other Program Summary of
2		Actual and Projected Capital
3		Expenditures;
4	Exhibit A-120 (MPK-10)	Wildfire Risk Mitigation Program
5		Summary of Actual and Projected
6		Capital Expenditures;
7	Exhibit A-121 (MPK-11)	IIJA Grant Funds Summary of
8		Actual and Projected Capital
9		Expenditures;
10	Exhibit A-122 (MPK-12)	Summary of Actual & Projected
11		Electric & Common O&M Expenses
12		Master;
13	Exhibit A-123 (MPK-13)	Summary of Actual & Projected
14		Electric & Common O&M Expenses
15		– Operations and Engineering;
16	Exhibit A-124 (MPK-14)	Summary of 5yr Historical O&M
17		Expenses;
18	Exhibit A-125 (MPK-15)	Summary of Actual & Projected
19		Electric & Common O&M Expenses
20		– O&M Programs Part 1;
21	Exhibit A-126 (MPK-16)	Summary of Actual & Projected
22		O&M Programs Part 2;
23	Exhibit A-127 (MPK-17)	Summary of Actual & Projected
24		O&M Expenses Cost Splits;
25	Exhibit A-128 (MPK-18)	Summary of O&M Expenses
26		Projected Using Inflation;
27	Exhibit A-129 (MPK-19)	Amended Reliability Roadmap;
28	Exhibit A-130 (MPK-20)	2020-2024 Distribution Unit Costs;
29	Exhibit A-131 (MPK-21)	2023 Electric System Loss Study
30		Report;
31	Exhibit A-132 (MPK-22)	Mitigating Wildfire Risk in
32		Consumers Energy’s Service
33		Territory (2025-2029);

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Exhibit A-133 (MPK-23)	Advanced Metering Infrastructure Metrics and Elements;
Exhibit A-134 (MPK-24)	Electric Distribution Summary of Actual & Projected Capital Expenditures per Rate Case Filing Requirements Attachment 11;
Exhibit A-135 (MPK-25)	Reliability Regression Analysis for Environmental Justice Communities;
Exhibit A-136 (MPK-26)	AMI Opt Out Charges;
Exhibit A-137 (MPK-27)	Environmental Justice Hosting Capacity Maps; and
Exhibit A-138 (MPK-28)	Reliability and Disconnections Regression Analysis Overview and Observations.

Q. Please explain the historical, bridge, and test year periods.

A. The historical year is calendar year 2024. The bridge period consists of the 16 months beginning January 1, 2025, and ending on April 30, 2026. The projected test year is the 12 months beginning May 1, 2026, and ending on April 30, 2027.

Q. How is your testimony organized?

A. Below is a Table of Contents that sets forth the subjects of my testimony.

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Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes. I will note that the Regression Analysis at Exhibit A-135 (MPK-25) and the summary at Exhibit A-138 (MPK-28) were prepared by a third-party consultant working with the Company.

I. EXECUTIVE SUMMARY

Q. What is the recent history of the Company’s approach to distribution planning?

A. The Company has produced a series of five-year distribution plans known as the EDIIP, the first of which was filed in March 2018, in Case No. U-17990. The most recent iteration of this five-year plan—the third EDIIP—was filed in September 2023, in Case No. U-20147. This most recent iteration is also known as the “Reliability Roadmap,” and that

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1 is the term that I will typically use in my direct testimony. An updated version of the
2 Reliability Roadmap is being provided in the instant case as Exhibit A-129 (MPK-19). The
3 first EDIIP dealt largely with the Company's then-existing distribution planning processes,
4 providing visibility for the Commission and other regulatory stakeholders. Since then, the
5 Company's approach to planning has evolved to include new tools and methods of analysis
6 to better anticipate future challenges, with those changes reflected in successive versions
7 of the filings.

8 The Reliability Roadmap, as amended in this case, defines the Company's current
9 distribution objectives and goals, and the investment plans to meet those objectives and
10 goals, which are reflected in the proposed spending levels in this case.

11 **Q. What are the key objectives for the Company's electric distribution system in the**
12 **Reliability Roadmap?**

13 **A.** In the Reliability Roadmap, the Company has established four key objectives for its electric
14 distribution system. These are as follows:

- 15 • **Safe** – The Company will continue to design and maintain its distribution
16 system to ensure the safety and security of customers and employees is
17 maintained and ultimately enhanced.
- 18 • **Reliable and Resilient** –To ensure system *reliability* during predictable
19 weather variations under normal operating conditions, the Company will
20 improve its capabilities and visibility to proactively operate the system and
21 better manage power quality to provide customers with a grid that remains
22 stable and available. To ensure system *resiliency* and performance, the
23 Company will harden the system where necessary to withstand abnormal
24 conditions driven by increasingly severe and unpredictable weather and climate
25 events.
- 26 • **Clean and Equitable** – The Company is building a system that will be
27 modernized, smart, and capable of accommodating changing customer
28 technology adoption patterns, such as electric vehicles ("EVs") and distributed
29 energy resources ("DERs"), for all communities served, ensuring members of
30 disadvantaged communities have equitable opportunities to participate. The

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Company will deliver reliability and resiliency equitably across all communities.

- **Competitive** – Provide affordable rates that create value for customers by attracting and retaining businesses that provide jobs and economic opportunities, while ensuring every community—especially our most vulnerable—sees effective energy investment according to its needs, with minimal impact and energy burden.

Q. How will the Company achieve these objectives?

A. I will cover each of these objectives in the section of my direct testimony entitled *Vision for Electric Distribution*. In general, the Company plans to meet these objectives through the multi-year investment plan established in the Reliability Roadmap.

This investment plan incorporates a variety of best practices and forward-looking approaches to achieve reliability through increased line clearing, asset hardening, rehabilitation, and automation.

Critically, the Reliability Roadmap calls for increased investment in many of these high-impact work types, ramping up over the next several years. Beyond the investments in the Reliability Roadmap, the Company is pursuing other activities intended to meet one or more of the objectives, and I will discuss these efforts in the *Vision for Electric Distribution* section of this testimony.

Q. How did the Reliability Roadmap compare to prior strategies presented by the Company?

A. The Reliability Roadmap involved a continuation and an expansion of the Company's long-term distribution strategy of (1) excelling at the basics, and (2) building for the future by reasonably and effectively modernizing the electric grid to deliver safe, reliable, and affordable electricity to customers today, and into the future.

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1 When considering the electric distribution system, “excelling at the basics” consists
2 of investments in and maintenance of core traditional infrastructure, like poles, wires, and
3 substations, all of which improve electric system reliability under normal operating
4 conditions, and resiliency under extreme conditions. The bulk of this work in reliability is
5 concentrated in the Reliability Program and is explained in detail for LVD by Company
6 witness Partlan, and for HVD by Company witness Hayward.

7 “Building for the future” consists of enabling the transition to cleaner energy
8 resources, including integration of DERs, and increasing automation of the system, using
9 advanced grid technologies to provide the Company’s customers with the technology and
10 tools to take greater control over their energy supply, reduce system waste, and optimize
11 DER use. Testimony detailing this work is featured in Company witness Partlan’s
12 testimony on Conservation Voltage Reduction (“CVR”) and LVD Lines Capacity, as well
13 as Company witness McPhail’s testimony on various Grid Automation initiatives.

14 **Q. Please summarize the electric distribution plan in this filing.**

15 A. In this filing, the Company is proposing to invest \$1,529,914,000 in distribution system
16 capital projects, and to spend \$300,994,000 in distribution system O&M in the test year;
17 as well as \$1,598,050,000 in capital projects in the 16-month bridge period. This O&M
18 spending is detailed later in my testimony, and includes programs related to line clearing,
19 as discussed by Company witness Stewart, and to service restoration, as discussed by
20 Company witness Snider.

21 Line clearing and service restoration both make critical contributions to the
22 Company meeting its electric distribution objectives. The Company’s electric distribution
23 system also includes streetlighting, which is addressed by Company witness Schmoekel.

Q. Which exhibits detail the capital for the bridge period and test year and the O&M for the test year?

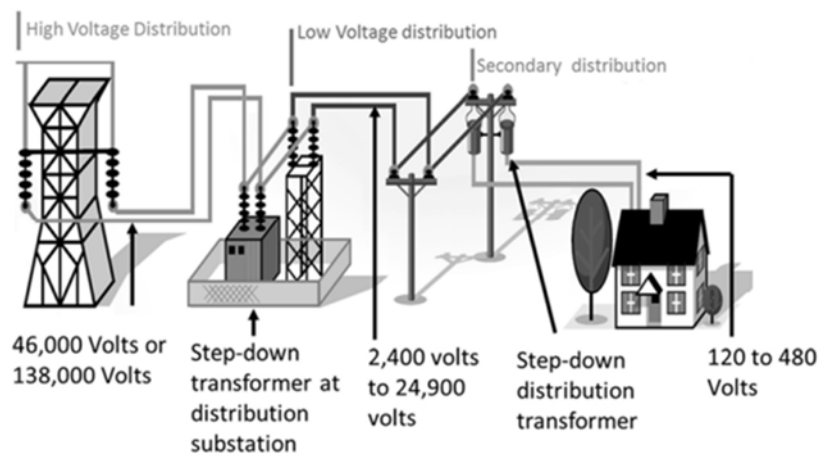
A. Capital spending for both the bridge period and the test year is outlined in Exhibit A-12 (MPK-1), Schedule B-5.7, through Exhibit A-121 (MPK-11). The O&M spending proposed for the test year is detailed in Exhibit A-122 (MPK-12) through Exhibit A-128 (MPK-18).

II. ELECTRIC DISTRIBUTION SYSTEM: OVERVIEW

Q. Please provide an overview of the Company's electric distribution system.

A. The Company's electric distribution system is comprised of the HVD, LVD, and Metro systems. The HVD and LVD systems are shown below in Figure 1.

FIGURE 1
HIGH VOLTAGE AND LOW VOLTAGE DISTRIBUTION SYSTEM OVERVIEW



Q. Please provide an overview of the LVD system.

A. The LVD system is comprised of more than 111,304 total miles of lines, made up of approximately 51,736 miles of primary overhead, 9,885 miles of primary underground, 31,209 miles of secondary overhead, and 18,474 miles of secondary underground.

The LVD system consists of 13 different primary voltages between 2.4 kV and 24.9 kV (grounded-wye and delta). The number of and range of primary voltages differ

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1 because the Company acquired several distribution systems from smaller distribution
2 companies throughout its history.

3 LVD primary voltage is then further stepped down at the distribution pole-top or
4 padmount transformer to a secondary voltage, serving businesses and residences at
5 voltages between 120 Volts and 480 Volts.

6 More than 2,000 LVD circuits serve the Company's 1.9 million electric customers,
7 where a circuit is defined as a combination of electrical devices and hardware that are
8 connected and emanate from an LVD substation to deliver electrical energy to customers,
9 operating at a defined nominal voltage.

10 The LVD system is expansive and subject to the greatest threat from common
11 outage causes like trees, lightning, unexpected load increases, and third-party damage. It
12 is largely a radial system that is not capable of continuing service to customers during
13 outages. Company witness Partlan explains in her direct testimony how the Company is
14 investing in the LVD system to provide reliability and resiliency of electric service to
15 customers. Company witness Partlan also explains in her direct testimony how the
16 Company is investing to convert, where possible, the LVD system from radial operation to
17 looped operation through use of Automatic Transfer Recloser ("ATR") loops.

18 **Q. Please provide an overview of the Metro system.**

19 A. The Metro system provides underground distribution service in the downtown areas of six
20 cities in the Company's service territory: Battle Creek, Flint, Grand Rapids, Jackson,
21 Kalamazoo, and Saginaw. Much of the Metro infrastructure was first installed in the 1910s
22 through the 1950s to accommodate electric distribution in already busy downtown areas.

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Metro infrastructure is used, both in the past and today, to deal with the density of downtown city centers, facilitate electrical repairs, and for aesthetics.

The primary benefit of the Metro System is to address space limitations where numerous utilities (electric, gas, telecommunications, water, and sewer) must use limited Right-of-Way (“ROW”) in public streets and alleys, especially because high-rise buildings have greater utility needs than in lower density areas. The Company’s Metro planning group focuses solely on these key downtown areas.

Q. Please provide an overview of the HVD system.

A. The HVD system is composed of two primary areas—lines and substations. Consumers Energy’s HVD system consists almost entirely of 46 kV lines (96% of the total HVD miles) and includes radial 138 kV and 69 kV lines (4% and <1% of the total HVD miles, respectively). The HVD system is made up of approximately 180 substations that contain HVD assets, 4,600 miles of HVD lines, and 1,100 LVD substations.

The HVD system is considered the backbone infrastructure of the electric distribution system because it connects the electric transmission system to the Company’s LVD system. The HVD system is largely a looped system that is capable of continuing service to customers despite the loss of any single component.

HVD investments are designed to ensure that the HVD system continues to provide a reliable backbone infrastructure critical to supplying the LVD system.

III. VISION FOR ELECTRIC DISTRIBUTION

Q. How is the Company’s vision for electric distribution presented?

A. The Company’s vision for electric distribution is presented primarily through its Reliability Roadmap, which was historically also known as the EDIIP. The third and most recent Reliability Roadmap was filed with the Commission on September 27, 2023, and is the

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1 Company's articulation of its electric distribution strategy. It is the underpinning document
2 for the distribution plans laid out in this rate case.

3 **Q. How has the Company's vision for electric distribution, as articulated in the**
4 **Reliability Roadmap, evolved over the last several years?**

5 A. The Commission first directed the Company to file a five-year distribution plan in an Order
6 in Case No. U-17990, primarily to give the Commission visibility into how the Company
7 made distribution investment decisions, and to provide a longer-term outlook into
8 investment plans beyond the single year contained in an electric rate case. In response to
9 this Order, the Company filed its first EDIIP in March 2018.

10 A series of further Orders in Case No. U-20147 in 2018 through 2020 expanded
11 Commission requirements for the Company's second EDIIP, which was filed in June 2021
12 ("2021 EDIIP"). The 2021 EDIIP introduced the concept of Grid Archetypes.

13 **Q. What are Grid Archetypes?**

14 A. Grid Archetypes were described in extensive detail in the 2021 EDIIP¹ filed in Case No.
15 U-20147. To summarize, the purpose of Grid Archetypes is to consider LVD circuit
16 characteristics beyond reliability metrics to prioritize investments, ensuring that
17 investments are optimally made across the Company's distribution system and across
18 different capital spending programs. This approach ensures that no section of the grid is
19 inadvertently left behind—that both rural and urban customers, and residential,
20 commercial, and industrial customers all benefit equitably from the Company's
21 investments. The seven archetypes, with general geographic locations, are shown in
22 Figure 2 below.

¹ MPSC Case No. U-20147; 2021 EDIIP, pages 51-56.

FIGURE 2
VISUAL REPRESENTATION OF GRID ARCHETYPE LOCATIONS



During planning, the Company allocates capital investment amounts across the archetypes, with each archetype receiving an amount that falls within a range bound by guardrails, as shown in Figure 3 below.

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FIGURE 3
LVD ARCHETYPE TARGETED SPENDING RANGES – ILLUSTRATIVE EXAMPLE

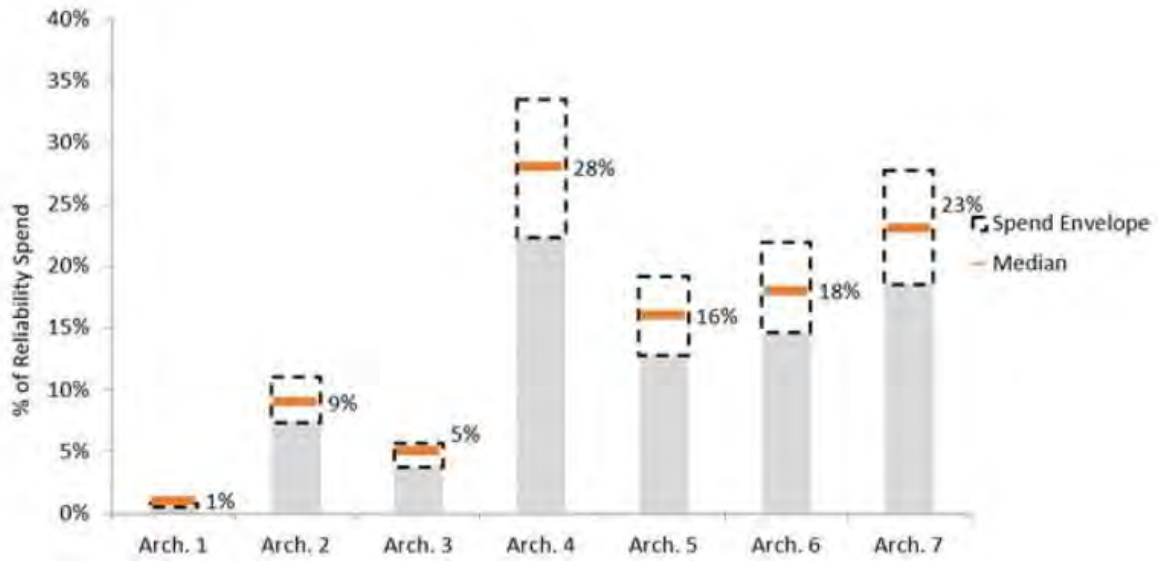


FIGURE 4
LVD ARCHETYPE CHARACTERISTICS

	Arch. 1	Arch. 2	Arch. 3	Arch. 4	Arch. 5	Arch. 6	Arch. 7
% of Line Miles	1%	6%	4%	18%	25%	17%	29%
% of Customers	1%	8%	9%	41%	14%	9%	18%

Q. Are Grid Archetypes updated on a regular basis?

A. Yes. The Company updates its Grid Archetypes periodically, typically every three to four years. The update process involves reviewing and reallocating circuits among the archetypes based on various circuit characteristics and performance metrics, as those characteristics and metrics evolve.

Q. What happened following the 2021 EDIIP related to the Company's distribution strategy?

A. The Company (and other utilities in Michigan) experienced unusually severe storms in August 2021 that caused widespread outages, leading the Commission to initiate a thorough review of reliability in Case No. U-21122.

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1 The Commission concluded that existing distribution investment plans were insufficient to
2 ensure reliability in a world where increasingly severe weather is likely, and in September
3 2022, the Commission directed the Company to file a new distribution investment plan by
4 September 30, 2023.² The Company duly filed its third EDIIP, the Reliability Roadmap,
5 on September 27, 2023, in Case No. U-20147 (“2023 Reliability Roadmap”).

6 In the instant case, the Company has made minor amendments to the 2023
7 Reliability Roadmap. These amendments primarily concern updating information to
8 reflect another year of actual historical reliability data, and to extend projected investments
9 by another year into the future. Some content has also been revised to reflect issues
10 highlighted by intervenors in Case No. U-21585, or raised by intervenors in other
11 regulatory areas, particularly in the Company’s third-party distribution system audit
12 conducted in Case No. U-21305. This amended version of the 2023 Reliability Roadmap
13 is included in the instant case as Exhibit A-129 (MPK-19).

14 **Q. What differentiated the 2023 Reliability Roadmap from the first two EDIIP**
15 **iterations?**

16 **A.** In developing the Reliability Roadmap, the Company took to heart the Commission’s
17 findings on reliability, as identified in the September 8, 2022 Order in Case No. U-20147,
18 particularly regarding the ability to improve reliability in the face of increasingly severe
19 weather. To address those findings, the Company included more robust analysis of future
20 reliability scenarios in its planning.

² MPSC Case No. U-20147, September 8, 2022 Order, page 67: “[C]urrent approaches to distribution planning, the Commission finds, are insufficient to address issues impacting the reliability of utility to service to customers – whether current issues or those forecast for the future. Put bluntly, Michigan’s distribution reliability is inadequate, and current plans for improvements are insufficient. Of paramount concern are continuing issues dealing with the safety and reliability of the system, including multiple fatalities within the month of August stemming from contact with downed wires as well as frequent and sustained outages stemming from storm events.”

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1 Consequently, the Reliability Roadmap evaluated multiple plausible future
2 scenarios, including a future with increasing severity and frequency of storms, rather than
3 assuming historical weather patterns will continue in the future. The Reliability Roadmap
4 then lays out a multi-year investment plan to address asset deterioration and maintain asset
5 health against identified risks while also hardening assets against increasingly severe
6 weather, so that customer reliability improves even if conditions worsen.

7 **Q. How did the Reliability Roadmap evaluate multiple plausible future scenarios?**

8 A. In developing the Reliability Roadmap, the Company identified the factors that would most
9 likely pose a future risk to the distribution system, with two major factors being identified:

10 a) increasingly severe weather; and

11 b) technological innovation driving increased demand on the grid, primarily
12 distributed solar generation, EVs, and electrification of heating.³

13 The Company's analysis indicated the most significant weather-related risks are
14 thunderstorms, other storms (i.e., extreme wind, ice storms), and high heat (which increases
15 demand and increases line losses).⁴

16 **Q. What scenarios did the Company develop for increasingly severe weather and for**
17 **increased technological innovation?**

18 A. The Company developed three scenarios applicable to both major risk categories, called
19 Decelerated Transition ("DT"), Continued Momentum ("CM"), and Accelerated
20 Transition ("AT"), which are described in detail in the Reliability Roadmap.

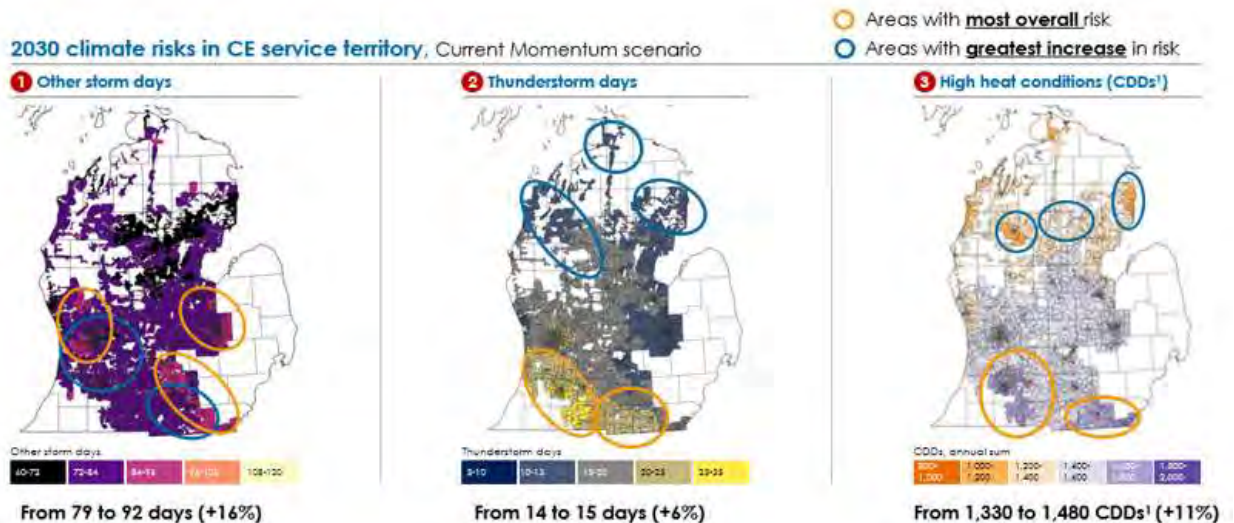
³ "Drivers of Change," Reliability Roadmap

⁴ "Key Impacts Modeled," Reliability Roadmap

Q. What conclusions can you draw from the Company's scenario modeling?

A. It is critical to note that, in any of the scenarios modeled, climate change will result in more severe weather and extreme heat, in turn creating increasing reliability and resiliency challenges for the distribution system. Regardless of climate policy, the Company's modeling projects an increase of 10-15% in severe weather-related outages by the early 2030s, compared to 2020 levels. The modeling also indicates load constraints due to electrification becoming a larger systemwide concern in the 2030s and 2040s, but this issue will remain localized to a small percentage of circuits for the remainder of this decade. *The most critical issue to focus on is reliability and resiliency in the face of storms, which is a more immediate threat.*⁵ The projected impacts are graphically summarized in the Reliability Roadmap as shown in Figure 5 below.

FIGURE 5
2030 CLIMATE RISKS IN CONSUMERS ENERGY SERVICE TERRITORY



This analysis aligns with the Commission's findings that previous distribution investment plans were not commensurate with the challenges posed by extreme weather.

⁵ "Impacts of Scenarios on the Distribution System," Reliability Roadmap

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1 Having performed this analysis in developing the 2023 Reliability Roadmap, the
2 Company was better able to identify *where* increased investment is needed, *what kinds of*
3 *investments* are needed, and *what levels of investment* are needed to harden the system and
4 improve reliability for customers even as weather worsens.

5 As discussed further below in my direct testimony, the Company has, in developing
6 the instant case, also evaluated other investment glidepaths that could affect *what levels of*
7 *investment* are planned on a year-by-year basis. These other evaluated glidepaths follow
8 recommendations in the Company's third-party distribution system audit conducted in
9 Case No. U-21305. As discussed later in my direct testimony, the Company has also
10 evaluated these different levels of investment and their resulting glidepaths against the
11 Commission's financial incentives and disincentives mechanism targets, established
12 through the Commission's February 27, 2025 Order in Case No. U-21400.

13 **Q. How does the Company intend to address the climate risks identified in the Reliability**
14 **Roadmap?**

15 A. In the face of these challenges, the Reliability Roadmap outlined the need to increase
16 investment to develop a modern grid capable of mitigating the immediate threats from
17 extreme weather. This was an increase, relative to prior investment levels, in the scale of
18 established investments in infrastructure and spending on line clearing and inspections,
19 while adding new types of resiliency investments.

20 **Q. Can you explain the third-party audit of the Company's distribution system in Case**
21 **No. U-21305?**

22 A. On October 5, 2022, the Commission issued an Order in Case No. U-21305 that directed
23 the Commission Staff to begin a third-party audit and review of all equipment and

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1 operations of the Company's distribution system and that of DTE. On July 11, 2023, the
2 State of Michigan awarded a contract to perform the audit to Liberty Consulting Group
3 ("Liberty"), following a public request for proposal process. Liberty was directed to file
4 their report in late summer 2024. Over a period of many months, Liberty representatives
5 met with key Company personnel to discuss the Company's distribution practices, and they
6 visited different Company locations to study the state of the Company's distribution
7 system. Liberty filed their report with the Commission on September 23, 2024, also in
8 Case No. U-21305, and presented remarks and responded to questions during the
9 Commission's open meeting on September 26, 2024. At the Commission's direction, the
10 Company filed comments on Liberty's report on November 15, 2024, in Case No.
11 U-21305. After other interested persons filed their own comments on December 16, 2024,
12 in the same docket, the Company filed reply comments on January 17, 2025.

13 The Company's November 15 comments and January 17 reply comments in Case
14 No. U-21305 present the Company's positions on items raised by Liberty in their report.
15 I will not re-state them in full here, but will discuss how the Company's distribution
16 strategy, as stated in the amended Reliability Roadmap, is incorporating Liberty's insights.

17 **Q. Which of Liberty's recommendations do you wish to address in your direct**
18 **testimony?**

19 **A.** In this direct testimony, I will specifically address audit issues with particular importance
20 for (1) the Company's distribution investment strategy, and (2) how distribution reliability
21 is measured. The positions taken in the Company's November 15 comments and
22 January 17 reply comments in Case No. U-21305 remain the same, even if I do not discuss
23 them here.

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1 **Q. Which Liberty recommendations do you wish to address related to distribution**
2 **investment strategy?**

3 A. Liberty recommended the Company place less emphasis on asset age when deciding
4 whether to replace assets. The Company generally agrees with this recommendation. The
5 Company does, in some cases, use age as one of many risk factors in determining whether
6 to replace an asset, but following Liberty's recommendation the Company is no longer
7 pursuing an age-based replacement plan for LVD poles, and will use LVD pole inspections
8 to identify where replacements are needed. Asset-specific approaches for identifying
9 assets for replacement, including how age is weighted, are discussed in more detail by
10 Company witnesses Partlan and Hayward.

11 Liberty also recommended the Company slow the pace of investment as defined in
12 the 2023 Reliability Roadmap, and evaluate different timeframes for how the Company
13 could meet its reliability goals. The 2023 Reliability Roadmap provided a System Average
14 Interruption Duration Index ("SAIDI") glidepath that would result in second quartile
15 SAIDI performance, excluding Major Event Days ("MEDs"), by 2029, or over
16 approximately five years from when the Reliability Roadmap went into effect⁶. The
17 Company has agreed to supplement the five-year glidepath with seven-year and 10-year
18 glidepaths for comparison, and these will be shown later in my direct testimony.

⁶ For purposes of this discussion, the Company is using the Institute of Electrical and Electronics Engineers ("IEEE") quartiles, in which second quartile SAIDI excluding MEDs is better than or equal to 128 minutes based on the five-year historical average (2020-2024 Benchmark Results for 2019-2023 Data). IEEE updates its quartiles each year, meaning the thresholds can change, but this analysis assumes a constant 128 minutes.

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1 **Q. What other Liberty recommendations related to distribution investment strategy do**
2 **you wish to address?**

3 A. Liberty recommended the Company accelerate its forestry line clearing cycle so that the
4 LVD system is on a four- or five-year cycle by 2028. As I will discuss later in my direct
5 testimony, and as Company witness Stewart discusses in her direct testimony in detail, the
6 Company has taken this recommendation into account and is planning to significantly ramp
7 up its line clearing activity to a five-year cycle, although not as rapidly as recommended
8 by Liberty. Increased forestry spending will lead to some adjustments in year-by-year
9 capital investments, but will not eliminate the need for capital investments, as I will discuss
10 later.

11 Liberty also recommended the Company not pursue its plan to convert open-wire
12 secondary (“OWS”) to multiplex, as outlined in the 2023 Reliability Roadmap, given the
13 limited SAIDI benefits. Liberty suggested that “considerations other than reliability
14 enhancement” would warrant OWS conversion. The Company continues to believe that
15 OWS conversion will deliver considerable benefits for public safety, and those benefits
16 will be particularly felt in vulnerable communities in the Company’s service territory.
17 Thus, the Company plans to continue with OWS conversions. However, to align with the
18 Commission’s final Order in Case No. U-21585, the Company is slowing its investment
19 pace in OWS conversions by approximately one half, and this is reflected in Company
20 witness Partlan’s testimony.

21 Additionally, Liberty recommended the Company delay its plans to convert
22 significant line mileage of overhead conductor to underground, other than the 10-mile pilot
23 approved by the Commission in Case No. U-21389. It is important to note the

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Commission declined to authorize any further Overhead-to-Underground conversion (“undergrounding”) beyond the pilot in its final Order in Case No. U-21585, because the pilot results had not yet been reviewed, so the Company does not plan to undertake any significant undergrounding work in the bridge period in the instant case. I will discuss the Company’s undergrounding plan beyond that, starting in the test year in the instant case, later in my direct testimony, particularly as the Company’s pilot demonstrates the cost-effectiveness of undergrounding at scale, and as considerable reliability and resiliency benefits will be produced.

Q. Are there any final Liberty recommendations related to distribution investment strategy that you wish to address?

A. Liberty generally did not find substantial need or benefit to increase investment in HVD lines or in substations, given the fact that most SAIDI minutes, and most projected SAIDI improvements, are related to the LVD system. In her direct testimony, Company witness Hayward discusses why the Company must invest in its HVD system to maintain the reliability and resiliency of the system’s backbone, and the Company plans to continue pursuing its investment strategy in this area. The Company is making some adjustments to its plans for HVD lines based on the Attorney General’s recommendations and the Commission’s Order in Case No. U-21585, finding that certain investment increases should be phased in over multiple years rather than done at once.

Q. What audit issues do you wish to address regarding how distribution reliability performance is tracked and measured?

A. Liberty assessed the Company’s historical SAIDI performance and concluded the Company has not improved its reliability over the past decade. The Attorney General and

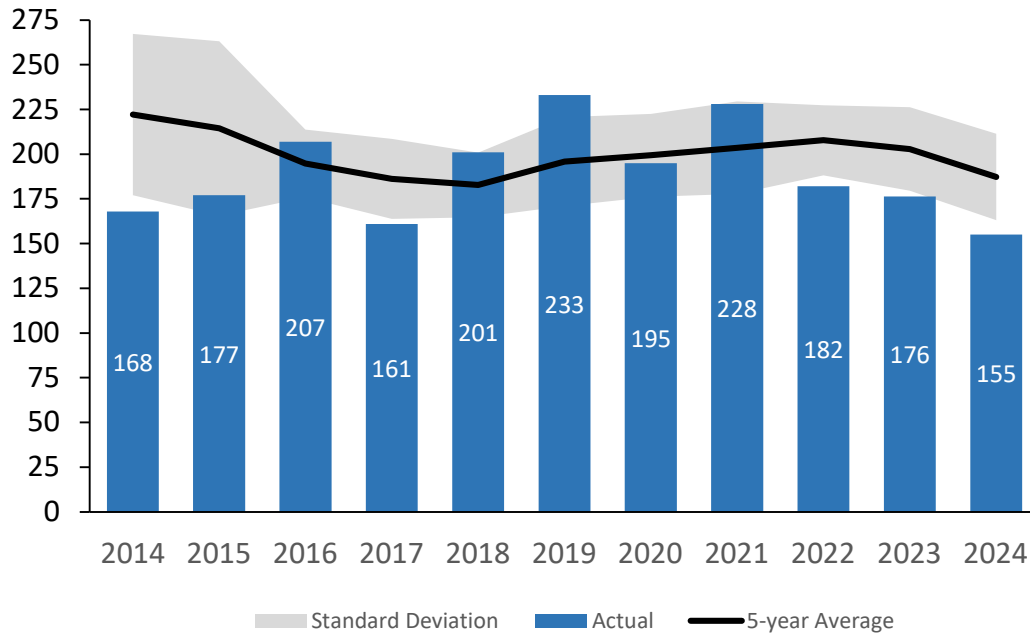
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1 the Michigan Environmental Council/Natural Resources Defense Council/Sierra Club/
2 Citizens Utility Board of Michigan (collectively “MNSC”) provided comments on this
3 point in response. The Attorney General argued that the Company’s analysis of historical
4 SAIDI is flawed because the Company focused on SAIDI excluding MEDs, while
5 all-weather SAIDI is more critically important for customers. The Company does track
6 and report all-weather SAIDI, and it is increasingly working to reduce it, particularly
7 through its Resiliency sub-program that was first introduced in Case No. U-21224 in 2022.
8 The Company’s IRM, proposed and approved by the Commission in Case No. U-21389,
9 was also explicitly intended to address MED outages. That said, SAIDI excluding MEDs
10 is a well-established industry standard metric, used to focus on reliability on a routine day-
11 to-day basis as the system is designed to handle. The Company is not trying to hide reality
12 or mislead.

13 Liberty analyzed SAIDI trends in no small part by comparing the Company’s
14 reliability in 2014 to its reliability in 2022, noting that 2022 was worse. The Company
15 submits that five-year rolling averages should be used for such comparisons, to limit annual
16 variability and to reduce the arbitrariness of which cut-off dates to use.

17 When the Company looks at its SAIDI excluding MEDs since 2014, we can see
18 that 2022, 2023, and 2024 were each greater than one standard deviation better than the
19 five-year rolling average, as shown in Figure 6 below. This illustrates that SAIDI
20 excluding MEDs has been consistently better than historical levels for the past three years,
21 which indicates that the Company’s reliability investments are delivering results.

FIGURE 6
SAIDI PERFORMANCE COMPARED TO STANDARD DEVIATION (2014-2024)



1 MNSC also concurred with Liberty in this area, and provided some similar
2 comments to the Attorney General, further arguing the Company’s reliability performance
3 has not improved relative to its peers. The Institute of Electrical and Electronics Engineers
4 (“IEEE”) updates its SAIDI quartiles each year to indicate where the industry is, which
5 allows for straightforward year-over-year comparisons of how a utility is doing relative to
6 its peers. Using Liberty’s 2014-to-2022 comparison for SAIDI and looking at the quartile
7 thresholds for the given years, the Company’s position relative to its peers improved for
8 both SAIDI excluding MEDs and all-weather SAIDI, as shown in Figure 7 and Figure 8
9 below.

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FIGURE 7
COMPARISON OF COMPANY SAIDI EXCLUDING MEDS TO PEERS

<i>(minutes of SAIDI)</i>	Single Year Comparison		5-year Rolling Average Comparison	
	2014	2022	2014	2022
Company Performance	168	182	222	208
Crossover point of 3 rd to 4 th Quartile Performance	159	191	162	179
Better/(Worse) than 3 rd /4 th Quartile	9 min / 6% Worse	9 min / 5% Better	60 min / 37% Worse	29 min / 16% Worse

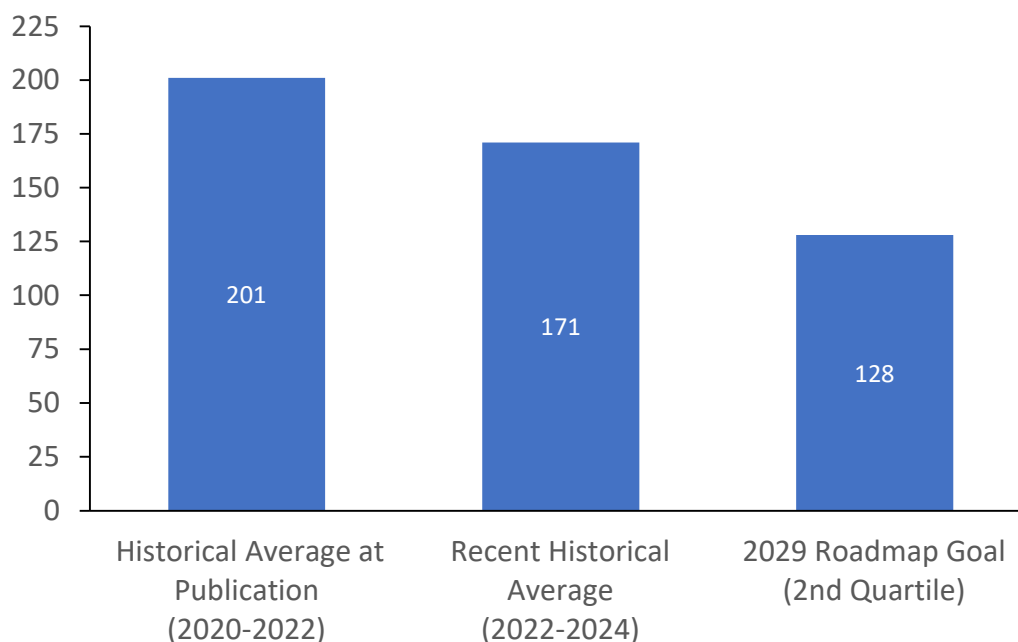
FIGURE 8
COMPARISON OF COMPANY ALL-WEATHER SAIDI TO PEERS

<i>(minutes of SAIDI)</i>	Single Year Comparison		5-year Rolling Average Comparison	
	2014	2022	2014	2022
Company Performance	377	467	625	597
Crossover point of 3 rd to 4 th Quartile Performance	261	455	451	445
Better/(Worse) than 3 rd /4 th Quartile	116 min / 44% Worse	12 min / 3% Worse	174 min / 38% Worse	152 min / 34% Worse

Q. What benefits are the investments in the Reliability Roadmap designed to deliver for customers?

A. When the Reliability Roadmap was published in 2023, its investments were projected to deliver SAIDI excluding MEDs in the second quartile or better by 2029, or five years after investments began substantially ramping up. The Company maintains this goal of providing its customers with better than average reliability performance, and the Company has demonstrated clear improvement in delivering reliable service to its customers, having already closed approximately 40% of this gap in performance since the Reliability Roadmap's filing.

FIGURE 9
SAIDI EXCLUDING MEDS PROJECTIONS –RELIABILITY ROADMAP GOAL



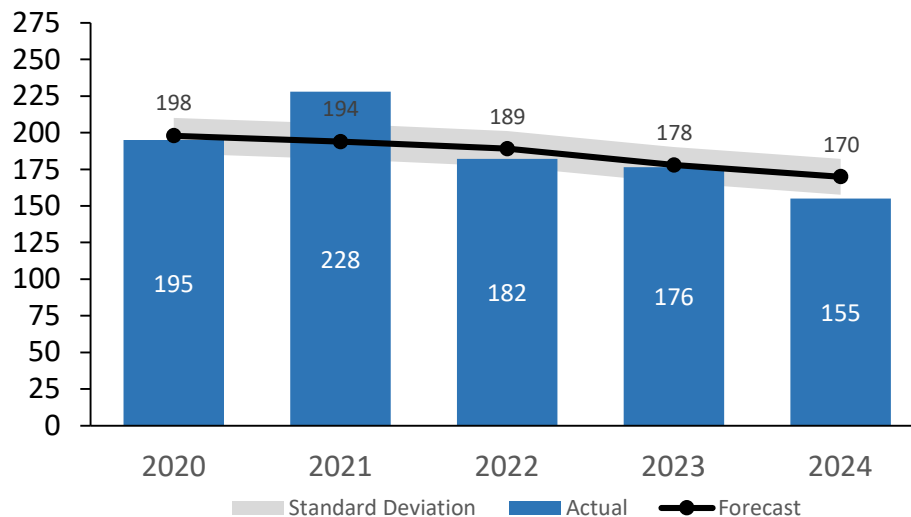
1 **Q. How does the Company project this improvement in reliability performance?**

2 A. The Company's model projects SAIDI, System Average Interruption Frequency Index
3 ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI") based on
4 historical relationships between these reliability metrics and forestry line clearing
5 spending, capital investment in the distribution system, and certain CAIDI improvements.
6 The model considers future projected forestry line clearing spending, capital investment in
7 key areas, and CAIDI improvements and, in return, the model projects SAIDI, SAIFI, and
8 CAIDI. This model does not incorporate all capital investment, but only those programs,
9 sub-programs, and investment categories that have historically been shown to be most
10 impactful on reliability metrics.

Q. What was the Company's SAIDI performance level in calendar year 2024 and how does this compare to the Company's SAIDI projection from the Reliability Roadmap?

A. The Company's SAIDI performance, excluding MEDs, was 155 minutes in 2024. The projected SAIDI performance for 2024 in the Reliability Roadmap, based on the proposed distribution capital investments, distribution O&M spending, and robust forestry line clearing plan was 170 minutes. While the Company's actual performance in 2024 was better than what was projected in the Reliability Roadmap when it was first filed in 2023, this result was still within 1.25 standard deviations of the projected. As with the variance in 2021, with an actual performance that was nearly 3 standard deviations from the projection, the Company expects actual performance to trend towards the projections, as with the results in 2022 and 2023. Variances are expected in projections, but the Company has confidence in its modeling of the glidepath given a total net variance over the past five years of seven minutes.

FIGURE 10
HISTORICAL SAIDI PROJECTIONS COMPARED TO ACTUAL

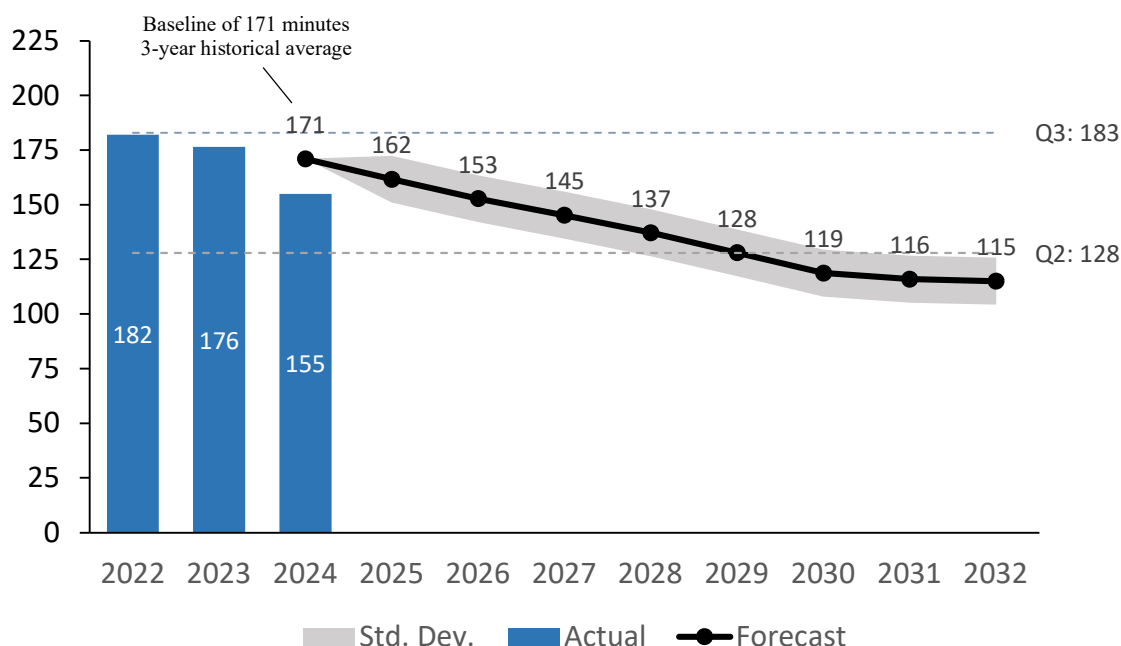


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Q. What SAIDI performance level is projected to be produced through the spending outlined in this rate case?

A. The Company's projected glidepath for achieving second quartile reliability, as measured by SAIDI excluding MEDs, remains its primary goal through 2029, and the investments proposed in the instant case will keep the Company on this glidepath. The Company estimates full approval for the spending levels outlined in this case will put the Company on a glidepath to a SAIDI performance of approximately 128 minutes, excluding MEDs, by 2029, a reduction of 43 minutes from the current baseline performance level of 171 minutes. The Company's requested distribution capital investments and distribution O&M spending, as well as the robust line clearing plan discussed by Company witness Stewart, support the planned glidepath to this improved SAIDI performance for customers.

FIGURE 11
SAIDI EXCLUDING MEDs PROJECTIONS



1 **Q. Please provide more detail on the Company's SAIDI glidepath.**

2 A. Using the model described above, the Company's projections for SAIDI, SAIFI, and
3 CAIDI are as shown in Figure 12 below. These figures are net of ongoing deterioration
4 because a certain amount of investment is necessary to keep up with deterioration and to
5 prevent performance from worsening.

FIGURE 12
RELIABILITY PERFORMANCE GLIDEPATH

	Baseline	2025	2026	2027	2028	2029
Net SAIFI	0.93	0.89	0.85	0.82	0.79	0.75
Net CAIDI	184	181	179	177	174	172
Net SAIDI	171	162	153	145	137	128

6 **Q. What Company investments and activities will support this improvement in SAIFI?**

7 A. The Company's model indicates certain investments and activities proposed in this filing
8 will affect SAIFI, as shown in Figure 13 below.

9 These figures are also net of ongoing deterioration. In some areas, shown as
10 negative numbers, the Company's investments and activities will drive a net reduction in
11 SAIFI over the glidepath period.

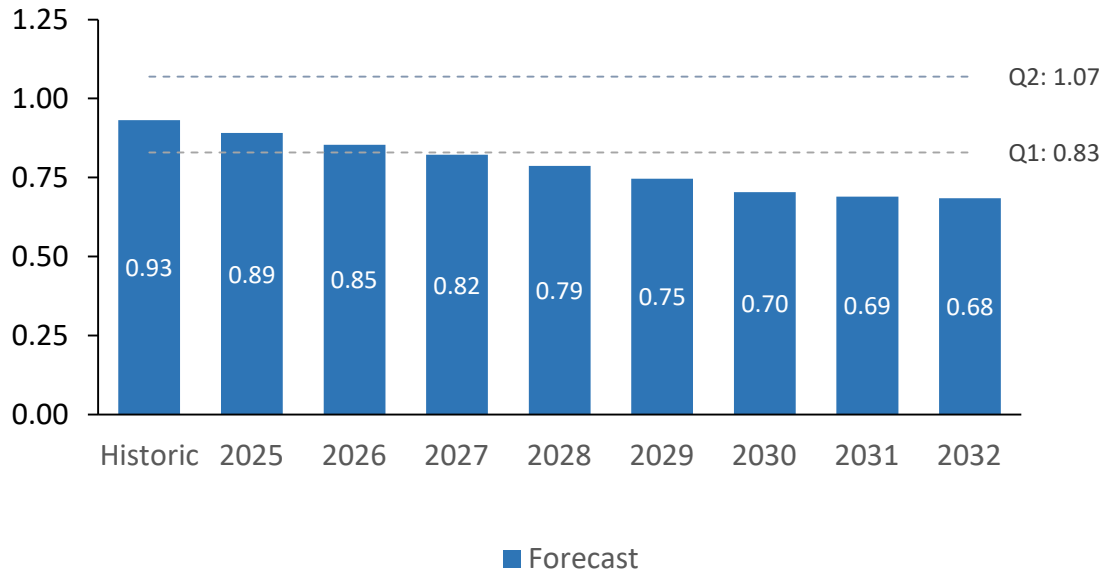
12 In other areas, shown as positive numbers, SAIFI will increase on net due to
13 deterioration; however, the Company's investments in these areas are still necessary to
14 prevent SAIFI from getting even worse. The figures shown for each year are cumulative,
15 not incremental.

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FIGURE 13
SAIFI GLIDEPATH IMPACT BY INVESTMENT/ACTIVITY AREA

Investment Category	2025	2026	2027	2028	2029
Line Clearing	(0.003)	(0.008)	(0.018)	(0.035)	(0.063)
Security Assessment Repairs	(0.017)	(0.033)	(0.048)	(0.061)	(0.073)
Zonal Health Projects	(0.024)	(0.042)	(0.050)	(0.057)	(0.063)
Fractionalization	(0.007)	(0.011)	(0.015)	(0.019)	(0.023)
Vulnerable Communities	(0.000)	(0.002)	(0.003)	(0.004)	(0.005)
LVD Pole Replacements	0.001	0.001	0.002	0.002	0.003
ATR Loops	(0.003)	(0.007)	(0.009)	(0.010)	(0.011)
Undergrounding	(0.000)	(0.001)	(0.004)	(0.006)	(0.008)
HVD Pole Replacements	(0.000)	(0.001)	(0.001)	(0.0000)	(0.000)
HVD Pole Top Rehabs	(0.000)	(0.001)	(0.002)	(0.003)	(0.004)
HVD Line Rebuilds	(0.000)	(0.002)	(0.005)	(0.007)	(0.009)

FIGURE 14
SAIFI GLIDEPATH

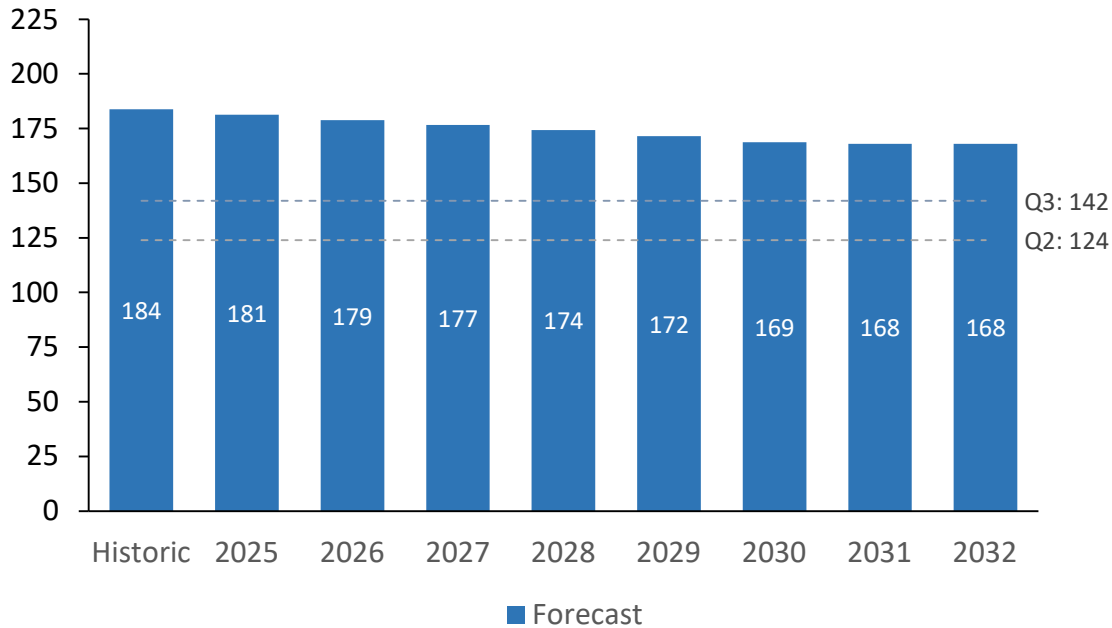


1 **Q. What is the CAIDI glidepath?**

2 A. The Company's model indicates that certain investments and activities proposed in this
3 filing will affect CAIDI, as shown in Figure 15 below.

4 As the number of outages is reduced, crews will have fewer outages to respond to;
5 this reduction in workload will allow crews to more quickly address outages that do occur.
6 This will produce CAIDI savings.

FIGURE 15
CAIDI GLIDEPATH



1 **Q. What else will the investments identified in the Reliability Roadmap address?**

2 A. Some investments identified in the Reliability Roadmap are also intended to address asset
3 health risk, a concept introduced on page 70 of the Reliability Roadmap.

4 In these situations, assets may not be experiencing poor reliability today, but the
5 Company has assessed that these assets are in poor health and at heightened risk of failure
6 in the near future. Investing in these assets will make the system more robust.

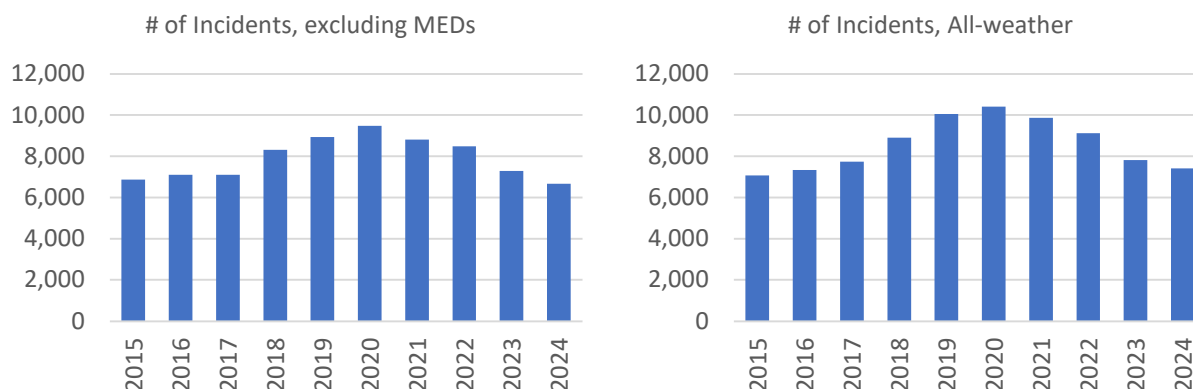
7 Company witnesses Partlan and Hayward both identify various investments related
8 to asset health risk. Although asset health risk applies to all Company infrastructure to
9 some extent, the issue is most prominent when considering the HVD system, substations,
10 and Metro infrastructure.

1 **Q. If the Company is increasing its line clearing, why are increased capital investments**
2 **still needed?**

3 A. Although line clearing is an important part of how the Company is working to improve
4 reliability, line clearing alone is not sufficient. For one thing, systemwide line clearing
5 benefits will take time to materialize even as the Company begins shifting to a five-year
6 clearing cycle. In remarks to the Commission on September 26, 2024, Liberty President
7 John Antonuk stated the full benefits of a five-year line clearing cycle would likely
8 materialize across the second iteration of the cycle. A line clearing-only approach,
9 therefore, would delay benefits to customers until the 2030s. To further emphasize this
10 point, the Company has not yet seen a significant systemwide decrease in tree-caused
11 outage incidents due to its increased forestry spending.

12 Conversely, capital investment in the distribution system has already begun
13 delivering reliability benefits. The Company began earnestly ramping up distribution
14 investments from 2018, when the first EDIIP was filed. Although this increased reliability
15 investment still only touches a small percentage of the system in a given year, the Company
16 began experiencing a clear downward trend in equipment failures starting in 2020, only
17 two years after beginning increased investment, as shown in Figure 16 below. Equipment
18 failure has been a significant contributor to SAIDI in its own right (see Figure 44 later in
19 this testimony). This downward trend indicates that investments have been well-targeted,
20 and that they quickly deliver benefits, and should therefore work in conjunction with
21 increases in forestry work.

FIGURE 16
EQUIPMENT FAILURES, 2015-2024



1 Even as the Company increases its line clearing activity, trees will still fall on LVD
2 lines and impact the distribution system. Trees are living organisms that are always
3 changing. A tree that poses no threat today may become a hazard before the next clearing
4 cycle (conversely, new assets do not begin to deteriorate to the point of failure for a much
5 longer period of time). This issue is clearly illustrated by the recent experiences of the
6 Lansing Board of Water and Light (“LBWL”). Liberty’s report highlighted LBWL’s line
7 clearing program since 2014, implemented in response to a catastrophic storm at the end
8 of 2013, and that LBWL has since completed two five-year line clearing cycles of its
9 system. Liberty noted that a July 1, 2024, storm resulted in about 10% of the Company’s
10 customers losing power, while a “very low number” of LBWL customers lost power.⁷
11 However, the large storm that impacted Michigan on May 15-16, 2025, illustrated how
12 utilities that follow an aggressive line clearing program can still face negative impacts from
13 storms. This storm left nearly one-third of LBWL customers without power
14 (approximately 32,000 customers), some of them for at least five days, with substantial tree

⁷ Liberty September 23, 2024 Report, Case No. U-21305, Part One, Chapter VI, pg. 51.

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1 damage reported.⁸ This further illustrates the need for appropriate capital investments to
2 be coupled with line clearing.

3 The Company's investments in hardening the system will reduce the number of
4 customer interruptions and/or make the interruptions shorter, countering the impacts trees
5 have on the system.

FIGURE 17
HEALTHY, OUTSIDE RIGHT OF WAY TREE IMPACTING DISTRIBUTION SYSTEM⁹



6 Finally, increased line clearing will eventually reach diminishing returns, or a point
7 at which continued increases will not create benefits in a cost-effective way. While line
8 clearing will be an increasingly important part of the Company's efforts to improve
9 reliability, it is not the only worthwhile approach to improving reliability for customers.

10 **Q. As the Company increases planned line clearing, is it making any adjustments to its**
11 **capital investment plan?**

12 **A.** Yes. The Reliability Roadmap, when first filed in 2023, presented a plan to ramp up
13 investments in the equivalent of 280 zonal health projects each year on the LVD system.

⁸ "BWL: Full power restoration efforts may take until May 21 after storm rips through region," *Lansing State Journal*, <https://www.lansingstatejournal.com/story/news/local/2025/05/16/power-outages-lansing-michigan-consumers-bwl/83666350007/>

⁹ Photo taken on 8/7/2015 conveying damage to Company's system - substation and circuit were not noted.

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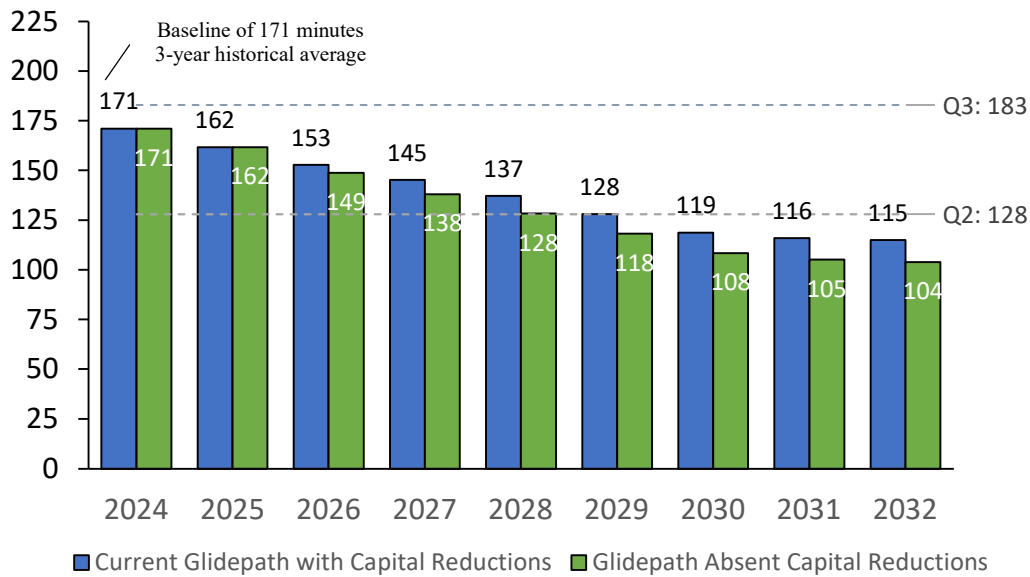
1 This ramp-up formed a critical component of the Company's projected SAIDI glidepath as
2 it was laid out in the Reliability Roadmap. Since the Company is now proposing a more
3 aggressive line clearing strategy, the SAIDI glidepath modeling discussed above indicates
4 the Company does not need to ramp its zonal health work up as significantly. With the
5 revised line clearing plan, the Company only needs to invest in the equivalent of 85 zonal
6 health projects per year.

7 This change in the equivalent number of zonal health projects results in an \$80 million
8 reduction in the capital that otherwise would have been requested by the Company. In the
9 instant case, this change shows up in the Company's test year plan in the LVD Lines
10 Reliability sub-program, which is discussed in detail by Company witness Partlan.

11 **Q. What would have been the Company's reliability performance had the Company not**
12 **made changes to its capital investment plan given the increase in line clearing?**

13 A. Had the Company not made the previously mentioned adjustment to the capital plan, the
14 Company would have been able to achieve the Reliability Roadmap goal of second quartile
15 SAIDI a year earlier than originally outlined in 2028 as shown below. The Company
16 maintains that its original timeline to achieve second quartile reliability is reasonable.

FIGURE 18
SAIDI PROJECTIONS WITH INCREASED LINE CLEARING



1 **Q. Has the Company considered alternatives in developing the Reliability Roadmap and**
2 **the investment plan contained therein?**

3 A. Yes. There are two different ways the Company considered alternatives in the context of
4 distribution planning.

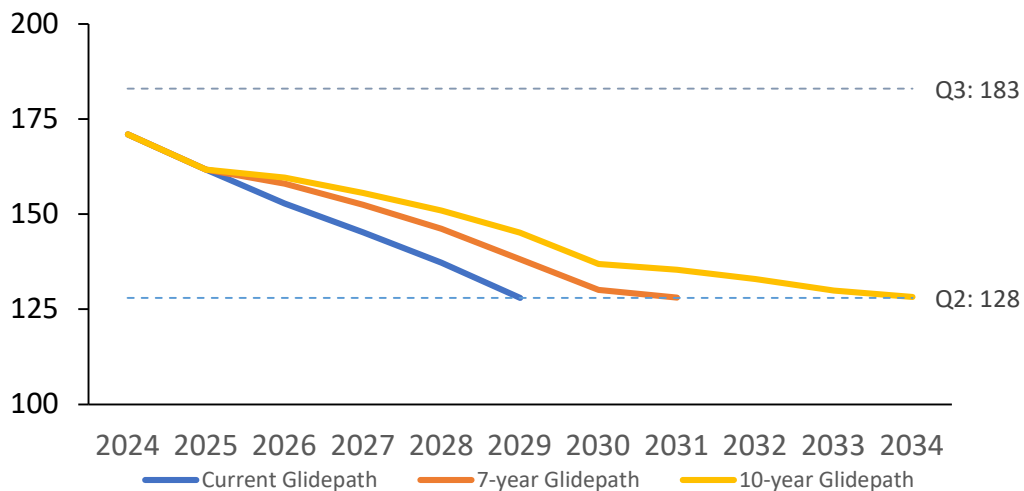
5 First, we considered alternatives to the Reliability Roadmap as a whole: Are there
6 alternatives to investing in the entire portfolio of assets laid out in the Reliability Roadmap,
7 and at the levels included in the Reliability Roadmap?

8 Second, we considered alternatives to individual projects: Is the Company
9 prioritizing its investments and choosing the best options to address identified issues on
10 the system? I will address the first of these concerns directly below. I will address the
11 second concern regarding how the Company chooses the right projects, later in my
12 testimony in the Capital Spending Overview section.

1 **Q. What alternatives has the Company considered regarding the overall scope of**
2 **investment laid out in the Reliability Roadmap?**

3 A. As noted above, the Reliability Roadmap would put the Company on track to providing
4 second quartile SAIDI excluding MEDs by 2029. Based on Liberty's recommendation,
5 the Company has also modeled what it would look like for the Company to slow its pace
6 of investment and reach that SAIDI target over seven or 10 years. The difference between
7 the Reliability Roadmap and these alternative slower glidepaths is illustrated in Figure 19
8 below.

FIGURE 19
Q2 RELIABILITY GLIDEPATHS



9 **Q. How would these slower glidepaths impact capital investment in the system?**

10 A. These slower glidepaths would nearly eliminate the most beneficial reliability and
11 resiliency programs for the LVD system. The seven-year glidepath would further reduce
12 the number of equivalent zonal health projects to 25 per year, and reduce the investment in
13 ATRs from 30 Loops to 10 Loops per year. The 10-year glide would completely eliminate
14 investment in zonal health projects and ATR Loops. These plans would reduce capital by

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1 approximately an additional \$35 million a year for the seven-year glidepath and
2 approximately \$50 million a year for the 10-year glidepath.

3 **Q. Are there any other concerns if the Company were to reduce its investments to align**
4 **with either of these alternative glidepaths?**

5 A. These alternative glidepaths would also result in the Company having a less diverse
6 portfolio of reliability investments.

7 With the near or full elimination of investments in targeted zones, ATR Loops, and
8 Fractionalization, the Company would be overly reliant on line clearance to achieve its
9 targeted performance.

10 **Q. Why does the Company believe it is important to invest at levels that will deliver**
11 **second quartile SAIDI by 2029?**

12 A. Pre-Reliability Roadmap investment levels would have led to gradual improvements in
13 SAIDI performance, but even by the end of the decade the Company's SAIDI performance
14 would still be in the middle of the third quartile. Likewise, the slower glidepaths suggested
15 by Liberty would leave the Company's performance lagging in the third quartile until well
16 into the next decade. Customers will benefit from the Company's plan for more rapid
17 improvement in reliability.

18 **Q. Why does the Company believe it is important to deliver better-than-average**
19 **reliability to customers?**

20 A. First and foremost, the Company is fundamentally committed to delivering reliable electric
21 service to its customers as a core business principle. Other parties have also indicated a
22 need for improved reliability.

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1 For example, the Citizens Utility Board of Michigan (“CUB”), a regular intervenor
2 in the Company’s rate cases, including in Case No. U-21585, publishes an annual “Utility
3 Performance Report” that assesses Michigan utilities by a variety of measures, including
4 reliability. In their 2024 edition of the Utility Performance Report, CUB begins its
5 executive summary by stating that “The data in this year’s report show Michigan utilities
6 continuing the long-term trend of highly unreliable electric service relative to utilities
7 across the country and those in neighboring states,” and “Michigan utilities have
8 continually failed to improve their basic reliability performance, a weakness that is likely
9 to be magnified during severe weather, which experts expect will be more common as the
10 climate continues to warm.”¹⁰ CUB’s emphasis on poor reliability in their Utility
11 Performance Report is typical of the statements made by these parties about reliability in
12 regulatory proceedings before the Commission; indeed, the first of the two quotes in this
13 paragraph is almost verbatim the same as one from CUB’s 2023 report, indicating that this
14 is an ongoing issue, and indicating a consistent demand for significant improvement in
15 reliability.

16 To cite another example, the Michigan Department of Attorney General has made
17 recent calls for improved reliability and has created a website¹¹ that seeks to collect power
18 outage data.

¹⁰ Available at https://cubofmichigan.org/wp-content/uploads/2024/12/Dec-2024_5LE_CUB_UTILTYperformanceReport.pdf.

¹¹ <https://www.michigan.gov/ag/initiatives/utilities>

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1 **Q. Are there any other external factors leading the Company to conclude that it must**
2 **invest at the levels defined in the Reliability Roadmap, as opposed to levels reflecting**
3 **more gradual increases and more gradual improvements?**

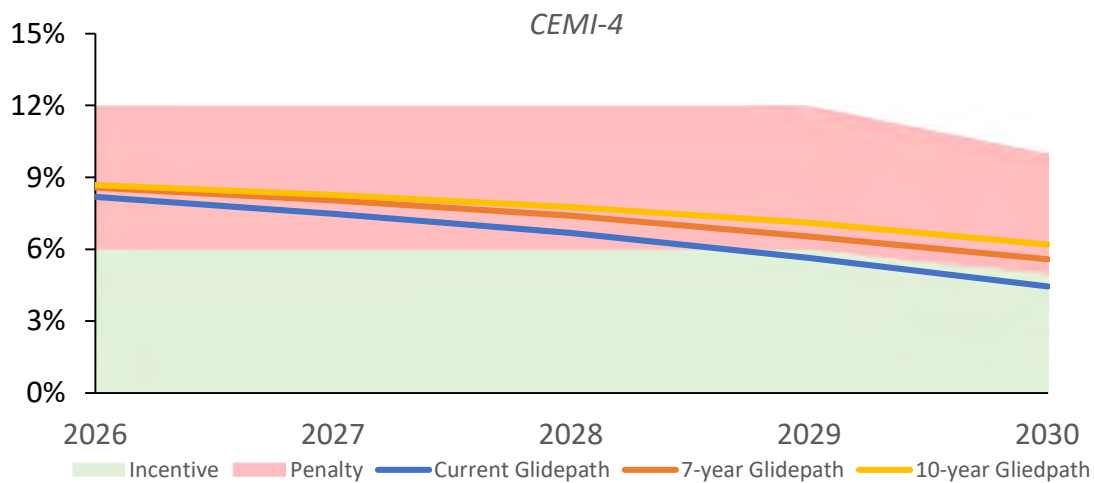
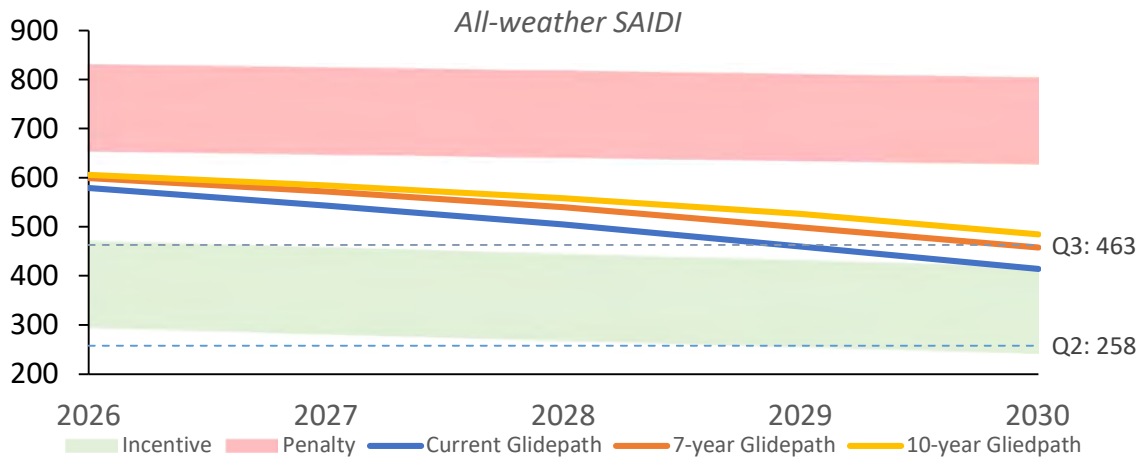
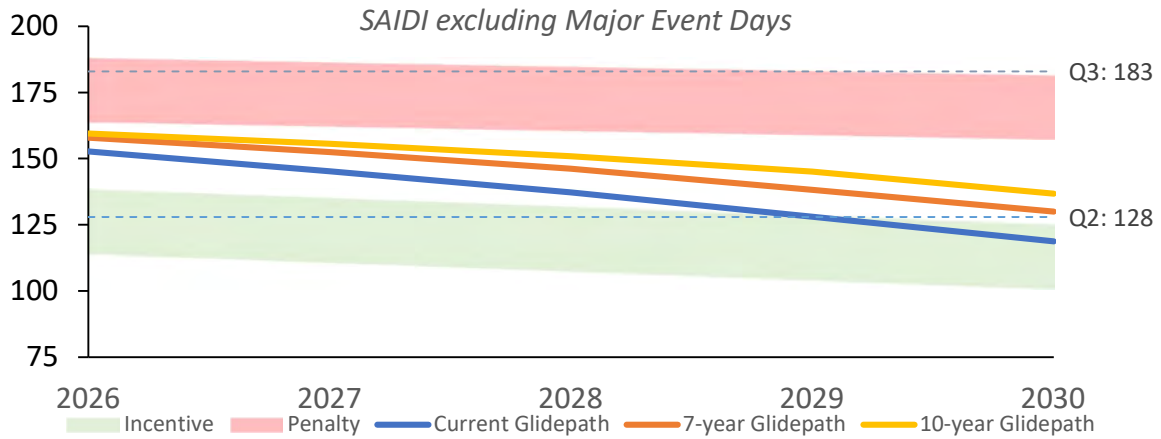
4 A. Yes. The Company must consider the reliability performance that it must deliver to meet
5 the targets established through the Commission's financial incentives and disincentives
6 mechanism in Case No. U-21400. This mechanism is commonly referred to as
7 performance-based ratemaking ("PBR").

8 The Company's PBR targets are being formally set in a separate proceeding in Case
9 No. U-21911, but the provisions set forth by the Commission in its February 27, 2025
10 Order in Case No. U-21400 define what metrics will be used, and the Order makes clear
11 what performance levels will be used for each metric to determine if incentives are earned
12 or penalties incurred.

13 In Figure 20 below, the Company has compared its projected performance
14 glidepaths for three of the PBR metrics under the Reliability Roadmap and both of
15 Liberty's more gradual approaches, against the targets based on the February 27 Order.

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FIGURE 20
PBR METRICS – GLIDEPATHS COMPARED TO TARGETS



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1 **Q. What does Figure 20 demonstrate?**

2 A. Figure 20 illustrates the investment levels set in the Reliability Roadmap put the Company
3 on a glidepath to meeting the Commission's incentive targets by the end of the decade.
4 Conversely, the slower approaches recommended by Liberty do not. For both SAIDI
5 metrics, the Company's performance remains in the deadband where no incentives or
6 penalties apply. For customers experiencing four or more outages per year ("CEMI-4"),
7 the Company's performance would remain in the penalty range. The Company must be
8 allowed to invest at a level that will allow the Company to avoid financial penalties
9 established by the Commission.

10 In short, both the Commission and various stakeholders expect significantly
11 improved reliability. That significant improvement in reliability can be achieved at the
12 investment levels outlined in the Reliability Roadmap, but not at the reduced investment
13 levels.

14 **Q. Is there a method for calculating a quantitative benefit from the implementation of**
15 **the Reliability Roadmap?**

16 A. Based on the Interruption Cost Estimate ("ICE") Calculator tool developed by Lawrence
17 Berkeley National Laboratory and Resource Innovations, and funded by the Energy
18 Resilience Division of the U.S. Department of Energy's ("DOE") Office of Electricity, the
19 Reliability Roadmap SAIDI projection will yield up to \$6.1 Billion worth of benefits in
20 avoided outage costs.

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1 **Q. Has the Company considered other means to achieve similar reliability improvements**
2 **as those projected in the Reliability Roadmap without the associated increase in**
3 **capital investment?**

4 A. The Company believes the investments and spending projected in the Reliability Roadmap
5 represent the right mix of work to deliver improved reliability.

6 In prior years, some parties have asserted that significant increases in capital
7 investment are not necessary to improve reliability, suggesting that because trees are
8 typically a leading cause of outages, the Company only needs to increase its line clearing
9 work to deliver improved reliability. Indeed, this point was raised in the Company's
10 distribution audit, which recommended the Company quickly move to a much more
11 aggressive line clearing cycle. It is important to note that:

- 12 a) prior to developing the Reliability Roadmap in 2023, the Company had already
13 significantly increased LVD line clearing from levels seen prior to 2021;
- 14 b) the Reliability Roadmap, as filed in 2023, included plans to further increase
15 LVD line clearing;¹² and
- 16 c) in 2024, the Company evaluated shorter LVD line clearing cycles in response
17 to the Commission's Order, and results were filed in Case No. U-20697 on
18 September 3, 2024.

19 Taking into account recommendations from the distribution audit and considering
20 additional data analysis and information that has become available, the Company is
21 proposing a ramp-up to a five-year LVD line clearing cycle, with a plan to be fully on-cycle
22 by the end of the 2030-2031 test period.

23 As previously discussed, the Company is also proposing more aggressive line
24 clearing through canopy removal on targeted three phase primary sections of circuits.

¹² Reliability Roadmap, p. 86.

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1 Company witness Stewart discusses this line clearing vision and provides detailed
2 justification of it in her direct testimony.

3 **Q. What other alternatives to capital investment exist besides line clearing?**

4 A. Various parties provided comments on the Reliability Roadmap in Case No. U-20147 in
5 February 2024.

6 Some comments stated the Company might have used the Reliability Roadmap to
7 give more consideration to non-wires alternatives (“NWAs,” sometimes also referred to as
8 non-wires solutions, or “NWS”), suggesting that DERs and other approaches could be used
9 to deliver reliability benefits. Similar arguments were made by some intervenors in Case
10 No. U-21585. I will address that suggested approach below.

11 Additionally, the Company could consider the alternative of simply letting more
12 assets run to failure rather than identifying asset health risks and proactively addressing
13 them. But this would do nothing to improve reliability; when assets fail, customer
14 interruptions are common, so running assets to failure as a matter of choice would lead to
15 worse reliability. Furthermore, reacting to failures is more expensive than proactively
16 addressing issues in a planned way, a phenomenon seen across the industry. For example,
17 the Company’s internal crew labor rates are double during storm responses compared to
18 the straight-time rates used for planned work.

19 **Q. Please summarize the Company’s views on NWS.**

20 A. NWS may be a viable option to improve distribution reliability, and the Company has
21 studied the potential of NWS in pilots in the last decade, which were discussed in detail in
22 the 2021 EDIIP. At that time, the Company had recently completed two NWS pilots. The
23 results of these pilots from 2017-2018 and 2019-2021 showed that successfully deploying

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1 NWS on the Company's system and generating benefits from those NWS would prove
2 difficult. In short, the Company's findings were that, for even a relatively limited use case
3 such as deferring an LVD substation capacity upgrade:

- 4 a) significant lead time was needed to procure the non-wires resources;
- 5 b) benefits in one case were unclear; and
- 6 c) benefits in another, while theoretically possible, were insufficient when one or
7 two large customers introduced new load.

8 Using NWS to deliver reliability benefits, as opposed to capacity benefits, requires more
9 certainty about deployment schedule and actual reliability parameters. As far as the
10 Company is aware, no U.S. utility to date has developed an NWS that works as an off-the-
11 shelf solution to improve distribution reliability.

12 **Q. Is the Company considering NWS in any other contexts at this time?**

13 A. In several regulatory proceedings since the 2021 EDIIP was filed, including in Case No.
14 U-21585, some intervenors have urged the Company to continue evaluating NWS. The
15 Company believes its conclusions to date are valid, but it is possible that other approaches
16 besides those used in earlier Company pilots could prove viable. Therefore, in 2025, the
17 Company is working to develop a new NWS pilot. The Company intends to propose this
18 pilot outside of the regular rate case process, using the expedited pilot process the
19 Commission created in its February 23, 2023 Order in Case No. U-20898. According to
20 the terms of the approved process, the Company plans to meet with stakeholders to seek
21 input during 2025, with a goal of filing a proposal as soon as is practicable through the
22 approved process.

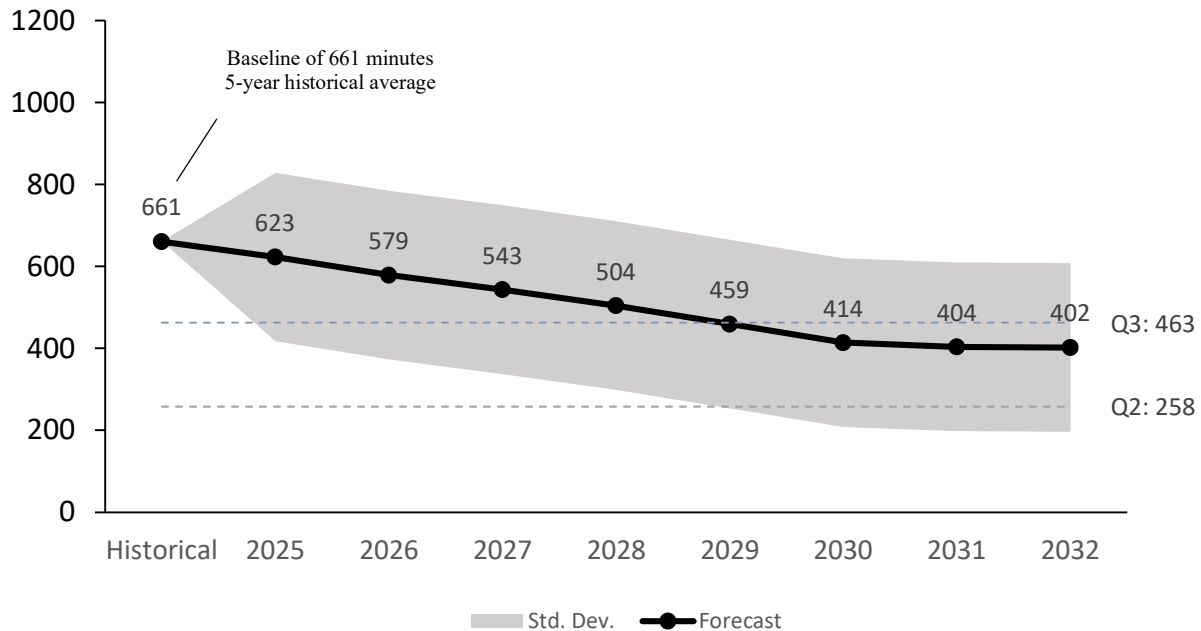
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1 **Q. Is the Company considering strategies to address reliability metrics other than SAIDI**
2 **excluding MEDs?**

3 A. Yes. Although the Company gives significant focus to SAIDI excluding MEDs, since it is
4 defined by IEEE and used as an industry-standard metric, the Company understands that
5 other metrics are also relevant. SAIDI including MEDs, or all-weather SAIDI, is important
6 to consider as it reflects the real day-to-day experiences of customers. The Company has
7 already been working to better address all-weather SAIDI, which requires investments to
8 improve resiliency as well as reliability.

9 In Case No. U-21224, filed in 2022, the Company first introduced its Resiliency
10 investment category as an early step to specifically target all-weather SAIDI. In Case No.
11 U-21389, the Company first proposed an IRM with an explicit goal of supporting
12 investments designed to reduce the occurrence of MEDs (see more discussion later in my
13 direct testimony on the IRM). In the instant case, the Company is proposing a new
14 Vulnerable Communities Resiliency Plan (also discussed later in my direct testimony) with
15 a specific goal of getting communities in economically vulnerable areas into the second
16 quartile of all-weather SAIDI. Furthermore, the Commission has established all-weather
17 SAIDI as a metric for its new PBR framework in Case No. U-21400; as the PBR framework
18 is fully implemented, the Company expects to develop even more investments intended to
19 improve all-weather SAIDI and meet the Commission's expectations.

FIGURE 21
ALL-WEATHER SAIDI PROJECTIONS



Finally, the Company has not met the Commission's Service Quality and Reliability Standards for CEMI-4 in recent years. CEMI-4 has also now been designated as a metric in the PBR framework. To meet the Commission's standards for CEMI-4, and to respond to the Commission's PBR incentives, the Company is increasing its investments in its LVD Repetitive Outages sub-program, as discussed by Company witness Partlan, to specifically target this metric.

Q. How is this rate case tied to the Company's Reliability Roadmap?

A. In short, the overall distribution plan outlined in this electric rate case corresponds with what was presented in the Reliability Roadmap in terms of investments and work activities that will take place during the bridge period and test year; as noted above, the version of the Reliability Roadmap included in the instant case as Exhibit A-129 (MPK-19) includes some amendments that differ from what was filed in September 2023.

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1 While the Reliability Roadmap lays out a distribution strategy and investment plan
2 over multiple years, this rate case translates particular years of that investment plan into
3 specific investment programs, sub-programs, investment categories, and projects.

4 **Q. Can all of the distribution investment included in this electric rate case be found in**
5 **the Reliability Roadmap?**

6 A. No. The Reliability Roadmap focused on strategic investments needed to improve
7 reliability and resiliency and/or address asset health risk. Investment not related to these
8 objectives, particularly in the New Business, Asset Relocations, and Demand Failures
9 programs were not discussed in significant detail in the Reliability Roadmap.

10 **Q. Does the Reliability Roadmap establish any other fundamental building blocks of**
11 **distribution strategy?**

12 A. The Reliability Roadmap also states the four distribution objectives that I defined in the
13 Executive Summary of this direct testimony: Safe, Reliable and Resilient, Clean and
14 Equitable, and Competitive. Taken altogether, these provide the Company with a
15 comprehensive distribution strategy. I will explain specific activities designed to meet
16 these objectives later in this direct testimony.

17 **Q. Are there any other factors that affect the Company's electric distribution strategy?**

18 A. Yes. While the Company is building for the future of the electric distribution grid, it is
19 simultaneously supporting the Company's Clean Energy Plan, which has been defined
20 most recently in the Company's 2021 Integrated Resource Plan ("IRP").

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1 **Q. Please explain how the Clean Energy Plan informs the Company's distribution**
2 **strategy.**

3 A. The IRP relied on the use of CVR, discussed in greater detail in the direct testimony of
4 Company witness Partlan, to reduce generation needs as a means of addressing the
5 Company's electric capacity requirements. The CVR investments discussed by Company
6 witness Partlan represent a continuation of this component of the Clean Energy Plan.

7 **Objective: Ensure safety and security**

8 **Q. How do the Company's proposals in this case support the Company's objective to**
9 **ensure safety and security to workers and the public?**

10 A. Improving overall safety and security for customers and employees remains the top
11 priority. The Company designs its distribution system to ensure safety is enhanced through
12 rehabilitation and preventative maintenance of assets as well as using automation
13 technology to spot issues before they occur. In particular, capital spending in the
14 Rehabilitation sub-programs proactively replaces assets judged to be at risk of imminent
15 failure by Company personnel. This vital work not only enhances the reliability of the
16 system by addressing system deterioration, but also protects the public from assets at a
17 higher probability of failure.

18 **Q. Do any of the investments identified in the Reliability Roadmap primarily support**
19 **safety goals?**

20 A. Yes. The Reliability Roadmap identified voltage conversions, subsurface transformer
21 replacements, open-wire secondary conversions, and key investments to improve public
22 safety. Additionally, the Company's new effort to perform groundline inspections of LVD

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poles and replace any pole in poor asset health will improve both public and employee safety. Company witness Partlan discusses these investments in her direct testimony.

Q. Is the Company performing any other work that will enhance public and employee safety?

A. Yes. The Company plans to continue the O&M spending associated with its Wildfire Risk Mitigation Program, first introduced in Case No. U-21585. The Company also proposed capital investments for Wildfire Risk Mitigation in Case No. U-21585, but these were opposed by some parties and the Commission did not approve the capital part of the proposal. Per the Commission's directions in their final Order in Case No. U-21585, the Company is pausing the capital investments associated with Wildfire Risk Mitigation while it reassesses the costs and benefits of the program utilizing data specific to its distribution system.

Q. What is the Company's Wildfire Risk Mitigation Program?

A. In the 2023 Reliability Roadmap, the Company analyzed multiple potentially emergent risks, such as wildfires and extreme precipitation, in its modeling.

As shown in Figure 22 below, these risks were originally deemed less immediate to Company assets compared to thunderstorms, high heat, and wind. However, multiple recent major wildfires in the United States, including wildfires triggered or exacerbated by utility infrastructure, illustrate the threat posed by wildfires. As a result, the Company has developed a program to mitigate wildfire risk. This plan is detailed in the Company's report *Mitigating Wildfire Risk in Consumers Energy's Service Territory*, which is included as Exhibit A-132 (MPK-22). In developing its plan, the Company researched other utilities' publicly available wildfire risk mitigation plans and held benchmarking

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discussions with several utilities, and concluded that there are four types of wildfire risk mitigation activities in use in the industry:

- **Situational Awareness:** Technology-based approaches that produce large amounts of data to inform decisions, including wildfire weather forecasting, enhanced inspections, sophisticated wildfire risk modeling, fire detection cameras, and fire spread modeling.
- **Operational Procedures:** Operating procedures designed to reduce ignition risk in wildfire-prone weather conditions, including modified field operating procedures, modified recloser settings, public safety power shutoff, and wildfire-specific emergency preparedness.
- **System Hardening:** Traditional investment in the system, including sectionalizing devices, installing covered conductor, undergrounding, and building microgrids.
- **Vegetation Management:** Increased frequency of line clearing, with expansion of scope to remove canopy on targeted three phase primary lines.

FIGURE 22
RELIABILITY ROADMAP CLIMATE RISKS EVALUATED



Q. What parts of the Company's system are at the highest risk from wildfires?

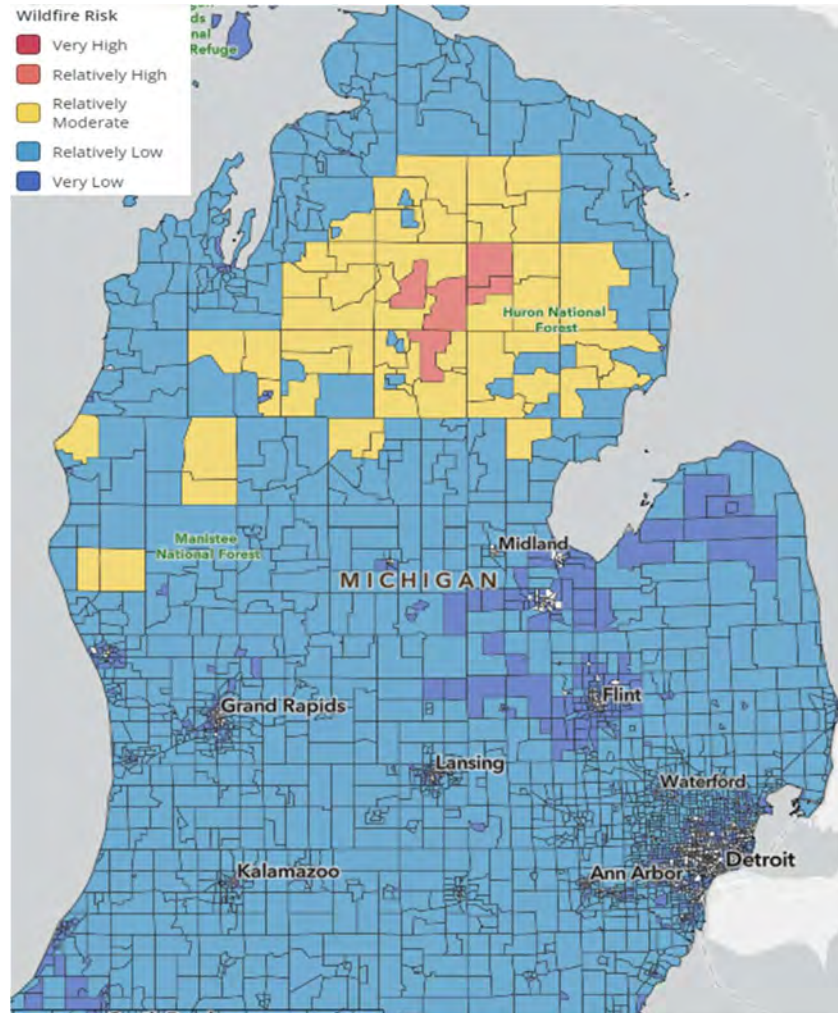
A. The Federal Emergency Management Agency ("FEMA") produces a *National Risk Index* map of the United States that includes a Wildfire Risk Index score and rating for communities, indicating their relative risk for wildfires compared to the rest of the country.

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According to FEMA, approximately 21% of the Company's service territory is located in areas with elevated wildfire risk, primarily in the north central Lower Peninsula. This is represented in Figure 23 below.

FIGURE 23

ELEVATED WILDFIRE RISK AREA IN MICHIGAN'S LOWER PENINSULA¹³



¹³ FEMA National Risk Index (<https://hazards.fema.gov/nri/map>)

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1 **Q. How does this risk level in Michigan, as defined by FEMA, compare to the risk levels**
2 **in other parts of the U.S. that have had severe utility-related wildfires?**

3 A. FEMA identifies Hawaii and Texas, two other states with major wildfires in recent years,
4 as having a small number of census tracts with a “Very High” risk whereas census tracts
5 in Michigan have a maximum rating of “Relatively High.”

6 That said, it is important to note the area surrounding Lahaina, Hawaii, on the island
7 of Maui, has a “Relatively High” rating by FEMA. This area experienced a devastating
8 utility-related wildfire on August 8, 2023, in which 100 lives were lost, 2,200 structures
9 were destroyed, and \$5.5 billion worth of property was damaged¹⁴.

10 While other states may have different climates from Michigan’s, the FEMA
11 wildfire risk ratings are comparable between Michigan and the area surrounding Lahaina,
12 Hawaii. Consumers Energy’s proposed wildfire program is a reasonable attempt to
13 mitigate wildfire risk in its service territory.

14 **Q. What work does the Company include in the Wildfire Risk Mitigation Program?**

15 A. Wildfire Risk Mitigation activities, and the corresponding work for 2025 through 2029, are
16 described in the Company’s wildfire risk mitigation report in Exhibit A-132 (MPK-22).
17 However, the work proposed in the instant case represents only a continuation of the work
18 approved in Case No. U-21585, including activities related to addressing situational
19 awareness, operational procedures, and vegetation management. System hardening capital
20 investments are not included in the instant case.

21 The Company intends to provide additional support for the capital needed to
22 mitigate the risk of wildfires in the communities in Northern Michigan in a future case.

¹⁴ <https://www.usfa.fema.gov/blog/preliminary-after-action-report-2023-maui-wildfire/>

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1 As shown in Exhibit A-124 (MPK-14), line 53, the Company is projecting \$512,000
2 in O&M in the test year in this case. This total amount is broken down as follows:

- 3 • \$12,000 for wildfire-specific weather forecasting; and
- 4 • \$500,000 for Light Detection and Ranging (“LiDAR”).

5 **Q. What are the Company’s plans for wildfire risk mitigation beyond the test year in the**
6 **instant case?**

7 A. The five-year plan presented in Exhibit A-132 (MPK-22) is the Company’s effort to be
8 fully transparent about future workplans and cost, as well as to follow industry best
9 practices for publishing multi-year wildfire risk mitigation plans. However, the Company
10 will continue to learn more about wildfire risk in Michigan, new wildfire risk reduction
11 strategies and technologies, and how changing weather patterns impact the region. As it
12 does so, it will continuously improve this plan by leveraging industry experts and peers,
13 and learning about and deploying best practices.

14 The Company is including an updated five-year plan in Exhibit A-132 (MPK-22)
15 to show the current vision for its Wildfire Risk Mitigation Plan given the Commission
16 order that only approved funding for O&M in Case No. U-21585.

17 Absent capital investment and the associated benefits of System Hardening, the
18 Company will leverage the three remaining best practices of Situational Awareness,
19 Operational Procedures, and Vegetation Management.

20 It is through these remaining activities that the Company will mitigate wildfire risks
21 in its Northern Michigan communities.

Objective: Ensure system Reliability and Resiliency

Q. How do the Company's proposals in this case support the Company's objective to improve reliability and resiliency?

A. The Company continues to invest hundreds of millions of dollars in the distribution system to ensure its reliability and resiliency, repairing and replacing distribution assets, performing line clearing work, and investing in technology and automation projects to modernize the grid.

As already discussed above, the Reliability Roadmap, with its investments to reduce SAIDI and reduce asset health risk, is driving a large increase in investment in reliability and resiliency. In total, the Company is directing \$697,127,000 of test year capital toward the Reliability Program.

LVD Reliability sub-programs are detailed in Company witness Partlan's testimony. Company witness Partlan also addresses the LVD Lines Capacity sub-program that also has clear reliability implications in the Reliability Roadmap. HVD Reliability sub-programs are detailed in Company witness Hayward's testimony. Grid Automation investments are detailed in Company witness McPhail's testimony. Additionally, the O&M dollars spent on line clearing improves reliability by mitigating the risk posed by trees adjacent to distribution assets.

To further support the Company's efforts to invest in reliability and resiliency, the Company is proposing an updated IRM covering certain capital investments, following the IRM approved in Case No. U-21389. The updated IRM is discussed by Company witness Heidi J. Myers, and additional details are included later in my direct testimony.

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1 **Q. What external sources has the Company consulted for industry best practices for**
2 **improving reliability and resiliency?**

3 A. The Company has consulted, among other things, the Electric Power Research Institute's
4 ("EPRI") *Distribution Grid Resiliency* reports published in 2015.

5 EPRI published a report on the prioritization of options for grid resiliency¹⁵
6 incorporating research that EPRI conducted on overhead structures, vegetation
7 management, undergrounding, grid technology, and storm response practices. This report
8 provided a benchmarking analysis of the costs and benefits of various options for
9 improving reliability and resiliency the Company can apply to its distribution planning, as
10 well as discussion on how to rank the reliability of circuits so that projects can be
11 prioritized.

12 While that EPRI report provides a foundation for the Company's distribution
13 investment prioritization, the Company continues to stay active in various EPRI working
14 groups, each of which allow Company personnel to stay up to date with best practices and
15 potential breakthroughs at other utilities or from others doing research. Within the electric
16 distribution space, these working groups include subject matter such as line design,
17 substation operation and maintenance, distribution cybersecurity, and integration of DERs.

18 **Q. Which Company proposals in this case specifically support the resiliency of the**
19 **system against increasingly severe weather?**

20 A. The Resiliency sub-program found in Company witness Partlan's testimony includes two
21 key efforts to support the resiliency of the system: Fractionalization and undergrounding.

¹⁵ *Distribution Grid Resiliency: Prioritization of Options*. EPRI, Palo Alto, CA: 2015. 3002006668.

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1 *Fractionalization* is the practice of segmenting LVD circuits into smaller sections with
2 fewer customers to reduce the impact of outages. *Undergrounding* completely replaces
3 certain sections of overhead LVD lines with underground lines and associated equipment
4 protecting distribution lines from weather and trees.

5 **Q. How has the Company been treating undergrounding in rate cases?**

6 A. In Case No. U-21389, the Company proposed an undergrounding pilot to allow the
7 Company to explore how undergrounding can help improve reliability for customers,
8 comparing the benefits and costs of this work. The Commission approved this proposal to
9 cover approximately 10 miles of undergrounding, and the Company executed on this work
10 in 2024 and early 2025. In Case No. U-21585, the Company proposed to expand on the
11 pilot work with an additional 25 miles of undergrounding as part of a multi-year initiative
12 to perform more undergrounding work as discussed in the Reliability Roadmap. That
13 expansion in Case No. U-21585 included mileage specifically dedicated to addressing
14 environmental justice (“EJ”) communities, and to addressing wildfire risk mitigation.
15 Ultimately, the expansion of the undergrounding conversion program was not approved in
16 Case No. U-21585 because the results of the pilot from Case No. U-21389 were not yet
17 available.

18 **Q. What have been the results, to date, of the pilot approved in Case No. U-21389?**

19 A. In Case No. U-21389, the Company included a list of circuits to be included in the pilot.
20 The Company was not able to convert some of these circuits to underground during the test
21 year due to an inability to secure easements. However, the Company was able to identify
22 substitute circuits for each of these cases using the same selection criteria the Company
23 defined when establishing the pilot in Case No. U-21389.

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Following these adjustments, the Company has fully field-completed undergrounding on 8.8 miles of lines, with the remaining miles that were approved in the pilot set to be complete in spring 2025. The pilot was particularly concerned with validating the costs of undergrounding. Ultimately the 8.8 miles converted in the test year of Case No. U-21389 had an average actual cost of approximately \$422,000 per line mile of underground installed.

Q. How do these costs per line mile compare to the Company's projections in Case No. U-21389?

A. In Case No. U-21389, the Company projected that underground conversions would cost \$400,000 per line mile, so the actual costs discussed above were, on average, higher. However, much of the discrepancy is due to a single outlier project included in the pilot. The Company converted 0.6 miles of the Saugatuck-Douglas circuit at a cost of \$902,000 per line mile. This project ended up costing much more than the others because it required full boring (as opposed to less expensive trenching or plowing) and it was in a narrow ROW with high customer density on a busy road requiring traffic control. If this outlier is discounted, the average cost for the pilot was approximately \$398,000 per line mile of underground installed.

In considering these averages, it is important to note that the Company also had projects in the pilot that came in cheaper. For example, the Company undergrounded 1.4 miles of the Conklin Park-Holly circuit in Newaygo for \$145,000 per line mile. This circuit was cheaper because it could be done entirely with plowing (as opposed to boring) and was in a low-density rural area with easy ROW access and away from busy roads.

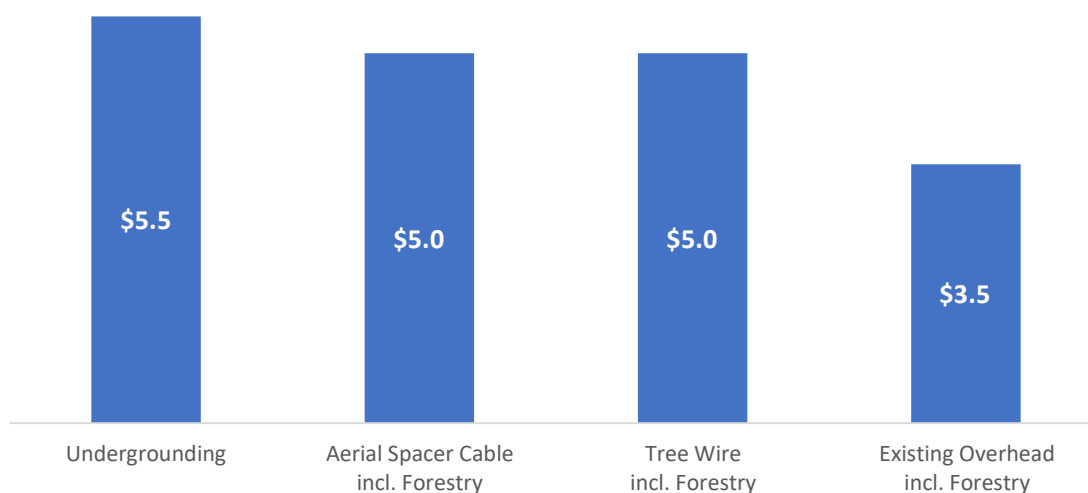
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Plowing is a technique for installing underground lines that involves a minimal amount of disruption on the surface, and it is therefore less expensive than boring.

Q. Based on the pilot results, how do the costs of undergrounding compare to alternatives?

A. The Company has compared undergrounding costs to those of hardening alternatives such as installing Aerial Spacing Cable and Tree Wire, and of simply maintaining traditional vegetation management. In Figure 24 below, the Company has compared the Present Value of the Revenue Requirement (“PVRR”) for its undergrounding pilot projects to the PVRR of installing Aerial Spacer Cable or Tree Wire for single-phase LVD. This figure is based on using the utility cost test (“UCT”), which is a cost-benefit analysis framework used to measure the costs and benefits incurred by the Company.

FIGURE 24
PILOT PROJECTS PVRR OF UNDERGROUNDING AND ALTERNATIVES - \$ MILLIONS



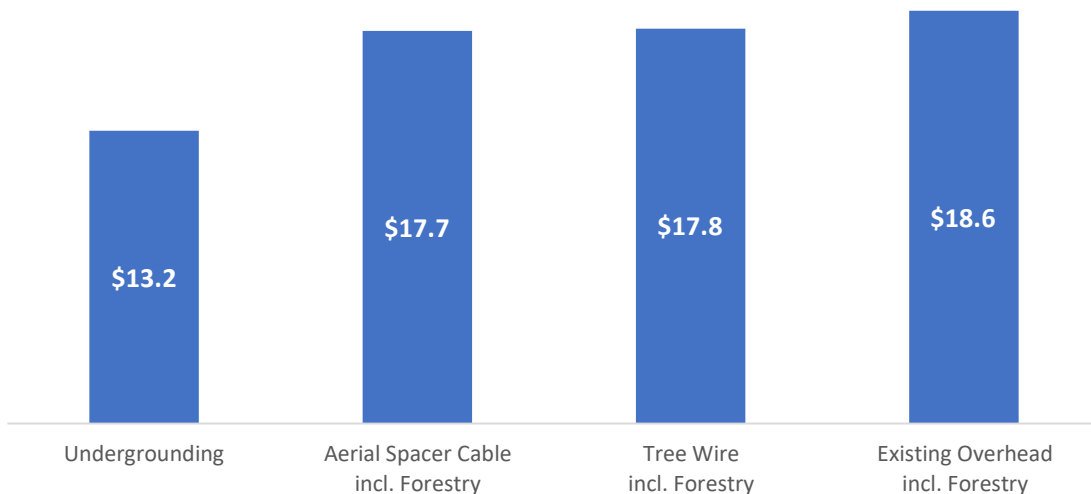
Q. How do the pilot costs of undergrounding compare to alternatives if viewed through a societal cost test (“SCT”)?

A. When using the SCT, undergrounding becomes the least cost option, as shown in Figure 25.

1 **Q. What is the SCT and how is it impacted by undergrounding?**

2 A. The SCT is an alternate methodology used to evaluate utility programs and their impact on
3 society as a whole. Although it is not applicable to all utility programs, it could be applied
4 to the undergrounding program to provide a comprehensive evaluation of benefits that are
5 not captured in the UCT. Given the long-term value provided to customers by
6 undergrounding, and the avoided external costs of outages resulting from the improved
7 resiliency provided by undergrounding, the SCT should be considered as a secondary tool
8 in evaluating the value of undergrounding. In general, the SCT uses a lower discount rate,
9 which assigns more value to long-term benefits provided by undergrounding, and it also
10 includes the customer cost of outages as calculated with the ICE Calculator. When taking
11 the long-term and society-wide perspective into consideration, undergrounding yields
12 better value to customers than the alternatives.

FIGURE 25
*PILOT PROJECTS PRESENT VALUE OF UNDERGROUNDING AND ALTERNATIVES
WHEN INCLUDING SOCIETAL COST OF CUSTOMER OUTAGES - \$ MILLIONS*



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1 **Q. Are the results of the SCT comparable to the UCT?**

2 A. No. Please note that the PVRR in the SCT and the PVRR in the UCT cannot be compared
3 directly to each other. The values in the UCT provide one means of comparison of the
4 alternatives, and the values in the SCT provide another means of comparison.

5 **Q. What other lessons has the Company learned from this pilot?**

6 A. Based on the range of actual costs incurred in the pilot projects, the Company has learned
7 that in addition to the selection criteria established in Case No. U-21389, it should also
8 identify locations where undergrounding costs are likely to be lower. In comparing the
9 Saugatuck and Newaygo results, the Company understands it can now prioritize
10 undergrounding work on circuits that meet its selection criteria and where construction is
11 simplified by minimizing the use of boring as the primary undergrounding technique,
12 avoiding the need to underground large amounts of secondary, especially under the
13 roadway, and avoiding customers who have a large number of unmarked private utilities.
14 It is clear that many undergrounding projects, if in the right locations, are competitive with
15 other non-undergrounding options, and undergrounding carries the added substantial
16 benefits of greatly improved reliability and resiliency, plus forestry work is then no longer
17 required.

18 **Q. How will undergrounding compare to the alternatives when at scale?**

19 A. Based on the lessons learned in project selection, the Company is better positioned to
20 identify economically competitive projects, unlike the one completed in Saugatuck. At
21 scale, the Company expects to continue to perform underground conversions at the
22 originally projected cost of approximately \$400,000 per underground mile.

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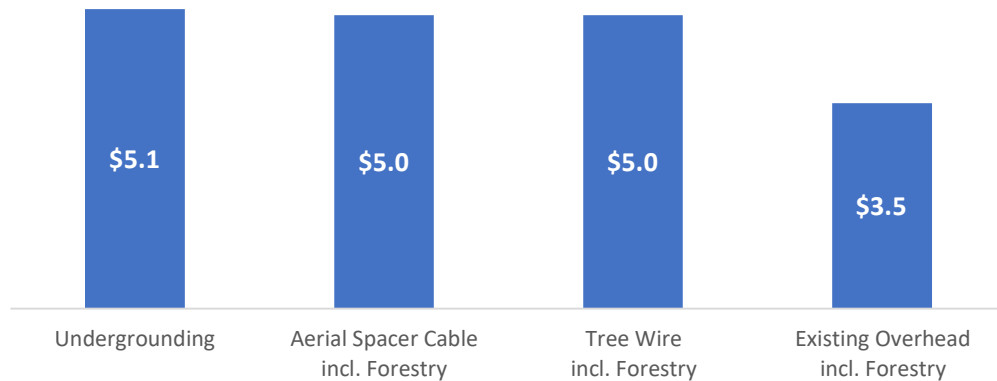
At this cost, the Company would expect undergrounding to be comparable to the alternatives using the UCT, without taking into consideration the societal costs and benefits. Using the SCT, undergrounding at scale will be approximately 30% more cost effective than the alternatives of Aerial Spacer Cable and Tree Wire.

Q. Why is it important to consider the costs of the pilot when at scale?

A. It is important to evaluate the relative costs and benefits of undergrounding at scale, because an analysis that includes only the pilot itself would have skewed results since it would not make adjustments to account for the lessons learned in the pilot.

As discussed above, these lessons learned allow the Company to develop a more economical program than the initial test cases conducted in the pilot that will yield benefits to customers at scale.

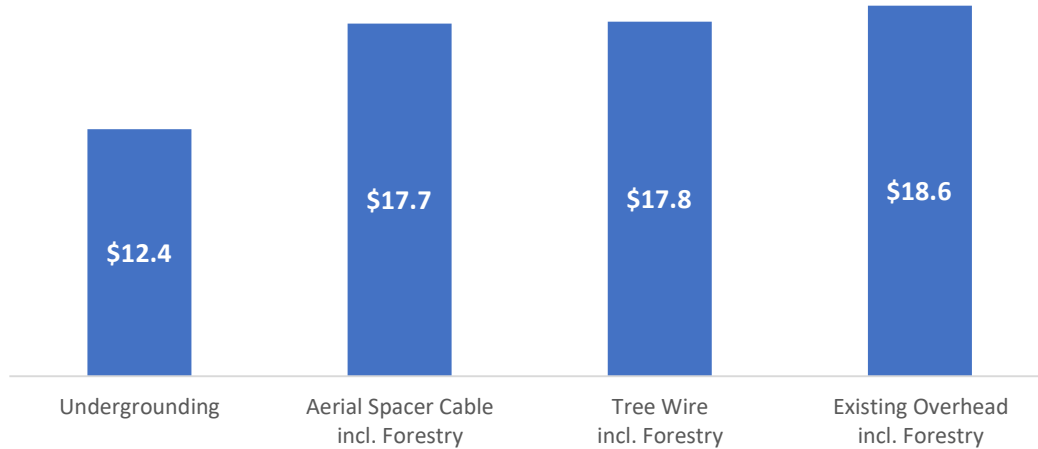
FIGURE 26
PVRR OF UNDERGROUNDING AT SCALE AND ALTERNATIVES - \$ MILLIONS



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FIGURE 27

*PRESENT VALUE OF UNDERGROUNDING AT SCALE AND ALTERNATIVES
WHEN INCLUDING SOCIETAL COST OF CUSTOMER OUTAGES - \$ MILLIONS*



1 **Q. How do the pilot and scaled costs of undergrounding compare to those cited in Case**
2 **No. U-21122?**

3 A. With an average cost of \$423,000 per mile for the pilot and \$400,000 per mile when at
4 scale, the Company is able to convert overhead to underground for nearly 50% less than
5 the \$974,000 per-mile maximum cost that the Company assumed in its October 1, 2021,
6 report in Case No. U-21122. Both costs are also less than the \$626,000 per mile average
7 cost cited in the same document.

8 **Q. What reliability benefit is undergrounding expected to provide?**

9 A. Based on work conducted by peer utilities, most notably WEC Energy Group and Alliant,
10 the Company would expect an improvement in reliability of 90% or more.

11 Any conductor that is not undergrounded, when in an area with trees, will always
12 be exposed to trees and susceptible to outages during severe weather. As shown later in
13 Figure 44, trees continue to drive a significant proportion of the Company's LVD SAIDI.

FIGURE 28

OUT OF RIGHT OF WAY TREE IMPACTING OVERHEAD LINE



1 **Q. What is the Company proposing regarding undergrounding in the instant case?**

2 A. The Company is proposing 50 miles of undergrounding in the test year, based on the
3 positive results of the pilot. As a result of the pause in the program, as ordered in Case
4 No. U-21585, the Company will not be fully up to the scale outlined in the Reliability
5 Roadmap in the upcoming test year.

6 **Q. How does the Company plan to scale undergrounding?**

7 A. The results of the pilot show that undergrounding is economically competitive, as described
8 above. Given the results of the pilot, the Company intends to scale the program to
9 400 miles per year by 2028.

10 **Q. Why is it important for the Company to continue undergrounding conversions?**

11 A. The Company is often compared to similarly situated utilities like those in Liberty's
12 Report, Part I, Chapter VI, which have larger percentages of their distribution systems
13 underground. Because of the size of the Company's distribution system, more miles need
14 to be undergrounded to better align with the Company's peers, on a percentage of system
15 undergrounded basis, and to provide customers with resiliency benefits comparable to

1 these similarly situated utilities. On top of its sheer size, given the inclement nature of
2 lake-effect weather, as noted by Liberty, the Company must invest in converting a
3 minimum of 2,000 to 9,950 additional miles to compare to regional peers and to provide
4 our customers with better reliability.

5 **Objective: Clean and equitable grid**

6 **Q. How does the Company's distribution strategy support a clean and equitable grid?**

7 A. The Company's distribution strategy is aligned with overall clean energy goals that involve
8 increasing sustainability and reducing waste. The Company also continues to execute on
9 a detailed strategy to understand the distribution reliability experience of EJ communities,
10 and to address any inequity found to exist.

11 **Increasing Sustainability and Reducing Waste**

12 **Q. How does the Company's distribution system support the Company's objective to**
13 **increase sustainability and reduce waste?**

14 A. In addition to providing Consumers Energy's customers reliable electric delivery service,
15 the Company's distribution investments are also designed to help facilitate the transition
16 to cleaner energy resources by integrating and optimizing DERs such as rooftop solar, as
17 well as EVs, onto the system.

18 The Company's CVR investments reduce system losses, helping the Company
19 meet load demand with less need for generation. The Company is considering sustainability
20 through a broader scope by also including EJ factors in its distribution planning. This focus
21 will address not only more equitable outcomes for customers, but also will lead to improved
22 understanding of where the distribution system has sufficient hosting capacity to accept
23 new distributed generation like solar.

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1 Finally, the Company continues to ensure its investments are right-sized and
2 appropriately targeted to avoid wasteful overbuilding of the system.

3 This can be seen, for example, in how the Company's Capacity Program
4 investments are designed to address reasonably known and foreseeable load growth
5 amounts without building more than is needed.

6 **Q. How is the Company preparing to integrate and optimize DERs?**

7 A. As technology matures and expands to more complex, larger, and widespread applications
8 of DERs, incremental steps to gain expertise around DER deployment is the most sensible
9 approach. The Company is laying the groundwork for this through its DER Optimization
10 initiative, detailed in Company witness McPhail's testimony. As this is rolled out in the
11 coming years, it will allow the Company to manage and coordinate Company and
12 third--party owned DER assets, applying best practices and lessons learned to deliver
13 solutions best suited for Michigan and customers. The DER Optimization initiative is more
14 important than ever, since the statutory distributed generation cap was increased from 1%
15 of utility load to 10%. The Company will need DER Optimization to ensure it can manage
16 that higher level of distributed generation on its grid.

17 The Company is also pursuing a grant through the Infrastructure Investment and
18 Jobs Act ("IIJA") to begin deploying distributed artificial intelligence ("AI") modules on
19 residential electric meters to quickly analyze high volumes of data to detect and classify
20 anomalies, and improve management of distributed assets. I discuss this further later in
21 my direct testimony.

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1 **Q. How is the Company planning for the rise in EVs on the distribution system?**

2 A. As discussed in Company witness Jeffrey A. Myrom's direct testimony, the Company is
3 working to optimize load from up to 1 million EVs in its service territory by 2030 in support
4 of the State of Michigan's policy goals. As noted in the Reliability Roadmap, the
5 Company's current modeling indicates the highest levels of customer technology adoption,
6 like EVs, will likely materialize on specific circuits, and while a limited number of circuits
7 may start to approach their capacity thresholds by 2030, the Company's system is not likely
8 to experience broader issues until closer to 2050.

9 **Q. Is the Company doing any other work in the area of increasing sustainability or**
10 **reducing waste?**

11 A. As more customers adopt new technologies like DERs and EVs, hosting capacity will
12 become a more prominent issue on the system, and hosting capacity analyses ("HCA") will
13 be important in addressing any concerns that arise. HCA is defined as "the amount of
14 DERs that can be accommodated without adversely impacting operational criteria, such as
15 power quality, reliability, and safety, under existing grid control and operations and without
16 requiring infrastructure upgrades."¹⁶ DERs interconnect to the distribution system through
17 a Commission-regulated process. HCAs can improve and streamline this process by
18 identifying locations on the system with a high probability of accommodating DERs.
19 While resource-specific analyses are still required with an HCA, an HCA can help
20 customers and DER developers avoid proposing interconnections and incurring study costs
21 in areas that are not suitable for DERs.

¹⁶ MPSC Case No. U-20147, August 20, 2020 Order.

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1 **Q. What is the Company's recent history with HCAs?**

2 A. In 2020, the MPSC directed the Company to pursue a "phased" approach to developing
3 HCAs, with two primary phases:

- 4 • Phase I: A base-level approach with a zonal go/no-go map; and
5 • Phase II: Specific, detailed analyses on areas of the distribution system with
6 high DER penetration, incorporating this information into a more detailed map
7 with circuit voltage-level information as DER penetration continues to increase.
8 The Company completed a Phase I analysis and reported the initial results in its 2021 EDIIP
9 filing, with a detailed description of Phase I methodology.

10 Since that time, the Company has updated its Phase I analysis as system conditions
11 have changed, and the Company maintains a publicly available updated version on its
12 website.

13 **Q. What does the Company plan to do regarding HCAs in the near future?**

14 A. The Company expects to have a more detailed Phase II analysis available by the second
15 half of 2025. For its Phase II analysis, the Company will be able to use maximum load
16 data from 2024 to create a snapshot of detailed hosting capacity information. This analysis
17 relies on the Distribution Resource Integration and Value Estimation ("DRIVE") tool
18 developed by EPRI, although in the future the Company may evaluate using other
19 platforms if appropriate. Because manual analysis is still required with current capabilities,
20 Phase II maps will be detailed but will not be updated in real time. Phase II hosting capacity
21 maps will show much more detailed circuit information than the existing Phase I maps.

22 **Addressing Distribution Equity**

23 **Q. How has the Company considered EJ factors in its distribution planning?**

24 A. In the Settlement Agreement in Case No. U-21224, the Company agreed with the other
25 parties that in future versions of the EDIIP and/or future rate cases, the Company would

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1 study reliability performance and hosting capacity on circuits that overlap with EJ
2 communities, which were defined as “census tracts that are above the 80th percentile on the
3 MiEJScreen Overall Score.” Since that time, the Company has engaged in ongoing,
4 increasingly detailed, analysis of distribution system performance in EJ communities,
5 which I detailed in testimony in Case Nos. U-21389 and U-21585.¹⁷ Those analyses have
6 built on one another, and each remains valid even as the Company has deepened its
7 understanding. The analyses presented in Case Nos. U-21389 and U-21585 indicated that
8 (a) on a systemwide basis, the Company’s EJ communities have comparatively good
9 reliability, but (b) there are particular EJ communities that do face reliability challenges,
10 and given their socioeconomic vulnerabilities the Company intends to direct specific new
11 investments to those communities to improve their reliability. In my rebuttal testimony in
12 Case No. U-21585, I introduced the Company’s plan to accomplish this goal, which is
13 being presented in more detail in the instant case as the Vulnerable Communities
14 Resiliency Plan.

15 **Q. What is the Vulnerable Communities Resiliency Plan?**

16 A. The Vulnerable Communities Resiliency Plan will make targeted strategic investments on
17 EJ circuits with a goal of ensuring that every EJ circuit in the Company’s service territory
18 has SAIDI, including MEDs, that is in the second IEEE quartile or better. In other words,
19 the Vulnerable Communities Resiliency Plan will ensure that no EJ circuits experience
20 worse than industry average reliability, and it will do so including MEDs to account for the
21 actual experience of those customers. The Vulnerable Communities Resiliency Plan will

¹⁷ For these analyses presented in prior cases, please refer to pages 48 and 49 of my direct testimony in Case No. U-21389; pages 2 through 16 of my rebuttal testimony in Case No. U-21389; pages 45 through 61 of my direct testimony in Case No. U-21585; and pages 5 through 19, 23 through 25, and 35 through 39 of my rebuttal testimony in Case No. U-21585.

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target EJ circuits, not EJ census tracts, because electrical geography (represented by circuits) does not always align with political geography (represented by census tracts). Circuits do not neatly follow census tract boundaries, and since investments are based on circuits (or zonal subsets of circuits), the Company cannot directly invest in “census tract reliability.” Since every circuit serving an EJ census tract is an EJ circuit, investing in EJ circuits ensures the Company invests in every EJ census tract.

Q. What investments does the Company propose as part of the Vulnerable Communities Resiliency Plan?

A. Over a period of several years, the Vulnerable Communities Resiliency Plan will include incremental investments that align with investment types that already take place in the Company’s Reliability capital program, particularly in LVD Lines Reliability and Resiliency. The total planned investments are as follows:

- Fractionalization: \$200 million of total investment
 - 6 new substations – one for each EJ circuit with over 3,000 customers
 - 133 new circuit exits – one for each EJ circuit with over 1,000 customers
- LVD line rebuilds: \$350 million of total investment
 - Rebuild 665 miles of primary LVD circuit to create a high-reliability mainline three-phase (i.e., aerial spacer cable or underground, based on local conditions)
- Other work: \$50 million of total investment
 - 400 new reclosers to ensure no protective zones exceed two miles in length
 - 335 new switches (i.e., one every mile)
 - Approximately 3,000 additional fuses

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1 **Q. Will all these investments be incremental to what was outlined in the 2023 Reliability**
2 **Roadmap?**

3 A. The new substations were already included in the Reliability Roadmap. The remainder of
4 the investments were not included in the 2024-2028 timeframe in the 2023 Reliability
5 Roadmap. It is crucial to emphasize the Company is *not* proposing to take reliability
6 investments already in the 2023 Reliability Roadmap and re-direct those to focus on the
7 Vulnerable Communities Resiliency Plan, which would disadvantage customers in other
8 parts of the Company's service territory. The Company will maintain its planned reliability
9 investments, and then perform these targeted EJ investments in addition to those.

10 **Q. What specific investments in the Vulnerable Communities Resiliency Plan are**
11 **included in the instant case?**

12 A. Proposed test year projects for the Vulnerable Communities Resiliency Plan are included
13 in Company witness Partlan's project list exhibit, and can be found in Exhibit A-167
14 (JMP-2), page 22. These investments represent a total of \$30,000,000, the first tranche of
15 investments in the plan noted above.

16 **Q. How does the Vulnerable Communities Resiliency Plan interact with the "EJ flag" in**
17 **Grid Archetypes that was presented by the Company in the 2023 Reliability**
18 **Roadmap?**

19 A. In general, the Vulnerable Communities Resiliency Plan should supersede the EJ flag. The
20 purpose of the EJ flag was to indirectly influence the planning and prioritization process to
21 make sure that EJ circuits were not ignored. The Vulnerable Communities Resiliency Plan

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1 identifies all EJ circuits, particularly those with poor recent reliability performance, and
2 simply steers direct reliability investment into those circuits.

3 **Q. How has the Company analyzed the reliability experience of EJ communities?**

4 A. The Company has conducted several analyses of EJ reliability, which were presented and
5 discussed in detail in Case Nos. U-21389 and U-21585. In its order in Case No. U-21389,
6 the Commission directed the Company to also conduct a regression analysis related to EJ
7 reliability. The Company spent considerable time in 2024 studying this issue, and did not
8 present a regression analysis in Case No. U-21585, but did spend time in dialogue with
9 MPSC Staff and other key intervenors.

10 In its final Order in Case No. U-21585, the Commission directed the Company to
11 also include information about residential shutoffs in its regression analysis. In the first
12 quarter of 2025, the Company has conducted the required regression analysis.

13 **Q. Please describe how the regression analysis was conducted.**

14 A. As noted above, the Company spent time in dialogue with Staff and other intervenors in
15 2024 about what a regression analysis should consider and how it should be structured.
16 The Company also sought input and lessons learned from other utilities who have
17 performed similar analyses in recent years. Based on this input, the Company determined
18 it would need to retain a third-party consultant to assist with the analysis, and developed a
19 request for proposal that was issued for competitive bidding. Once a consultant was hired,
20 the consultant's representatives took part in additional dialogue with Staff and intervenors
21 on analysis design and early analysis results. The analysis considered widespread types of
22 Company data as well as publicly available data, particularly on socioeconomic and
23 demographic issues. The full analysis, with its methodology, is being provided in this case

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as Exhibit A-135 (MPK-25). All of the underlying data that was used in the regression analysis is also being provided in this case as workpaper WP-MPK-1, which will allow other interested parties to review the analysis and conduct their own analyses if desired. In addition to this data, the regression analysis also made use of other publicly available data, and the report in Exhibit A-135 (MPK-25) describes how this data was obtained and how it could be obtained by other parties. All of this data, and the analysis itself, should also address the other EJ-related data requirements promulgated by the Commission in its order in Case No. U-21389.

Q. What results did the regression analysis show?

A. As described in detail in Exhibit A-135 (MPK-25), a single regression analysis was not performed. Instead, a large number of different types of statistical analyses were performed, including different types of regression analyses, to evaluate questions of differing reliability performance and differing experiences with involuntary shutoffs across areas of differing socioeconomic status and other conditions. A large number of individual analyses yielded statistically insignificant results, making it difficult to discuss all of the results in a fully comprehensive manner. However, it is possible to group the analyses into a few categories and discuss some of the statistically significant results in that manner.

First, multiple analyses compared average reliability of different types of census tracts, comparing EJ vs. non-EJ tracts; urban and rural tracts; low-income and high-income tracts; and high-percent-minority vs. low-percent-minority tracts. These analyses indicated that, when statistically significant differences exist, it is consistently the EJ, urban, low-income, and high-percent-minority tracts that have better reliability. This is

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1 congruent with the Company's own analysis as presented in Cases Nos. U-21389 and
2 U-21585.

3 Second, multiple regression analyses studied census tract-level reliability. Where
4 statistically significant correlations exist, these analyses showed that higher MiEJScreen
5 scores are correlated with improving reliability. However, these analyses also showed
6 instances where increasing poverty levels and increasing unemployment rates are
7 correlated with worsening reliability, in terms of SAIDI and SAIFI as well as outage
8 duration.

9 Third, multiple regression analyses studied circuit-level reliability, with particular
10 attention to classifying circuits by whether they serve EJ census tracts; whether they serve
11 urban census tracts; whether they serve low-income census tracts; and whether they serve
12 high-percent-minority census tracts. These analyses found no significant correlation
13 between reliability and whether a circuit serves urban, low-income, or high-percent-
14 minority census tracts. However, they did find instances where circuits serving EJ census
15 tracts are more likely to experience customer interruptions, as measured by SAIFI
16 excluding MEDs.

17 The regression analysis findings related to residential shutoff rates will be discussed
18 by Company witness Jessica R. Byrom. I will discuss my conclusions regarding the equity
19 of reliability below.

20 The regression analyses, and their conclusions, are further summarized in the
21 presentation provided as Exhibit A-138 (MPK-28).

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1 **Q. What conclusions do you draw from the regression analysis regarding equity of**
2 **reliability?**

3 A. As I have already noted, a large number of individual analyses performed in this exercise
4 returned no statistically significant results. The results discussed above represent those
5 fairly few instances where clear results could be identified. It is not clear that regression
6 analysis as a whole is well-suited to analyzing the electric distribution system in this
7 manner.

8 With that caveat, the first set of analyses mentioned above – evaluating whether
9 one set of census tracts or the other have better reliability – seem to confirm the Company’s
10 analyses as presented in Case Nos. U-21389 and U-21585. There is nothing apparently
11 systemic or unique about EJ census tracts (or other potential groupings of disadvantaged
12 census tracts) as a whole that give them worse reliability, since they average better
13 reliability than other census tracts.

14 Still, the regression analyses of census tract-level and circuit-level reliability also
15 indicate that there are some ways to interpret data that indicate that there are certain areas
16 within EJ communities that do face worse reliability. This confirms the crux of the
17 Company’s analysis as presented in rebuttal in Case No. U-21585 (which is also discussed
18 in the Reliability Roadmap in Exhibit A-129 (MPK-19) in the instant case), which
19 identified individual EJ circuits with poor reliability. That analysis in Case No. U-21585
20 led the Company to develop the Vulnerable Communities Resiliency Plan. These
21 regression analyses of census tract-level and circuit-level reliability further underpin the

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1 need to make targeted investment in those EJ communities that do have poor reliability,
2 given their particular vulnerability to frequent and/or extended outages.

3 **Q. Has the Company produced any maps to graphically represent reliability in EJ**
4 **communities?**

5 A. The Commission's Order in Case No. U-21389 directed the Company to work with Staff
6 to develop a means for interested parties to access Geographic Information System ("GIS")
7 data from the Company, and the Company undertook this effort during late 2024 and early
8 2025. This process has resulted in two new public outputs. First, the Company has
9 posted interactive GIS maps to its public website that show EJ circuits overlaid
10 with EJ census tracts in the Company's service territory, showing SAIDI and
11 SAIFI by circuit, with and without MEDs. These maps can be accessed at:
12 <https://experience.arcgis.com/experience/1d84e089ff5e4a2382df340d15689488>.

13 Second, the Company has created an online form on its public website that allows
14 interested parties to access GIS data. This form can be accessed at:
15 <https://www.consumersenergy.com/about-us/electric-generation>.

16 **Q. How has the Company worked to improve storm restoration in EJ communities?**

17 A. In early 2025, the Company created a dashboard for use during restoration activities that
18 highlights outages on circuits that impact EJ Communities. This dashboard helps to ensure
19 the Company is maintaining a focus on the customers who are some of the most impacted
20 by outage events caused by storms.

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1 **Q. Has the Company performed any hosting capacity analyses related to EJ**
2 **communities?**

3 A. Yes. This was another stipulation agreed to in the Settlement Agreement in Case No.
4 U-21224. Prior to this filing, the Company had only completed a hosting capacity analysis
5 for its entire system that determined whether a circuit has 2 MW of hosting capacity, and
6 this information was presented in Case Nos. U-21389 and U-21585. Since the Company
7 is moving to a more detailed Phase II hosting capacity analysis in 2025, as discussed above,
8 that new analysis will also include the hosting capacity of EJ circuits. While that Phase II
9 analysis is still in progress, the Company is providing its preexisting hosting capacity
10 analysis for EJ circuits in Exhibit A-137 (MPK-27).

11 **Objective: Provide competitive, affordable rates**

12 **Q. What avenues is the Company pursuing in its distribution strategy to deliver**
13 **competitive, affordable rates for customers?**

14 A. The Company is seeking federal government funding for reliability and resiliency projects
15 through the IIJA to leverage federal funds to achieve reliability goals.

16 **Q. How will seeking federal funding through the IIJA help the Company optimize system**
17 **costs?**

18 A. The IIJA offers federal funding to support various infrastructure projects throughout the
19 United States, including certain types of utility infrastructure. If the Company is able to
20 obtain federal funding to support distribution infrastructure investment, then the portion of
21 the costs of that infrastructure funded by federal grants would not be passed on to
22 customers.

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1 **Q. Has the Company been selected for any federal funding through the IIJA?**

2 A. Yes. To date, the Company has been selected for four grants related to grid reliability and
3 resiliency, and is in the process of negotiating with the DOE on the final terms:

- 4 • **Section 40101(c): Grid Resilience Program.** Under this section of the IIJA,
5 the Company was selected for a \$100 million grant running through 2028. This
6 grant could provide the Company with approximately \$20 million each year in
7 matching funds to perform sectionalization and circuit improvement work in
8 federally-defined disadvantaged communities (“DACs”).
- 9 • **Section 40101(d): Grid Resilience Grants.** According to the Michigan
10 Department of Environment, Great Lakes, and Energy (“EGLE”), Michigan is
11 expected to receive a \$38 million grant for “preventing outages and enhancing
12 the resilience of the electric grid.” The Company was selected by EGLE to
13 potentially receive \$4.05 million as part of this grant.
- 14 • **Section 40101(d): Grid Resilience Grants (state and tribal program).** Under
15 this section of the IIJA, the Company was selected by the Nottawaseppi Huron
16 Band of Potawatomi tribe to implement a \$500,000 grant to perform pole top
17 rehabilitation and other HVD upgrades to improve reliability.
- 18 • **Section 40107: Grid Resilience and Innovative Partnerships.** The Company
19 is partnering with Utilidata, the Electric Power Research Institute (“EPRI”),
20 GM Energy, and the University of Michigan on this grant, which is worth
21 \$19.9 million. The Company was selected to receive this grant in October 2024.

22 **Q. Has the Company received any funding related to the grants?**

23 A. No. The Company has not yet received funding related to the grants as the Company is
24 still in negotiations with the Department of Energy on the terms and conditions.

25 **Q. Will the Company have to match funds provided by the federal government?**

26 A. Most, if not all, of the funding opportunities being offered through the IIJA require a
27 grantee percentage match. Recipients of the offered funding must match a varying
28 percentage of the funding awarded to use the grant dollars. In the case of the Section
29 40101(d) and the two Section 40101(c) grants listed above, the Company expects to match
30 the funds provided by the federal government. Because of this provision, the full costs for
31 the associated work are included in my capital exhibits, and the portion being provided by

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1 the federal government is listed as negative dollar amounts in Exhibit A-12 (MPK-1),
2 Schedule B-5.7, lines 9 and 19, and itemized in Exhibit A-121 (MPK-11).

3 **Q. Why is the Section 40107 grant not included as having the federal government**
4 **providing funding?**

5 A. The Section 40107 grant is not far enough along in negotiations for the Company to be
6 certain of project timing and funding from the federal government. As such, the Company
7 is not seeking reimbursement of costs, and is not indicating any grant funding from the
8 federal government in this instant case.

9 **Q. Please provide more details regarding the work that will be done related to the grant**
10 **under Section 40101(c) of the IIJA.**

11 A. Under Section 40101(c), the Company plans to perform targeted reliability improvements
12 directed toward Michigan's vulnerable communities. Funds are expected to be used to
13 increase sectionalizing on circuits, minimizing the number of customers impacted by a
14 single fault, and constructing new tie lines for circuits currently with no ties to neighboring
15 circuits. ATR loops between these circuits and their new ties would also be added. The
16 new tie lines would harden the system at the ends of circuits and create three-phase load
17 addition capabilities where currently only single phase exists.

18 **Q. Please provide more details regarding the work that will be done related to the grants**
19 **under Section 40101(d) of the IIJA.**

20 A. For one of the grants under Section 40101(d), the Company expects to perform
21 rehabilitation work on the Athens HVD line in 2025, and on related nearby LVD circuits
22 in 2026, to improve reliability for the Nottawaseppi Huron Band of Potawatomi tribe near
23 Athens, Michigan.

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1 For the other grant under Section 40101(d), EGLE has received a block of federal
2 funding. The Company expects \$4 million in grant funding from this block through EGLE
3 to perform undergrounding of service drops and upgrades of secondary voltage lines in EJ
4 communities.

5 If the Company receives this funding from EGLE as expected, the Company
6 expects that 372 residential customers will be directly impacted through secondary and
7 service work. These customers are in Kalamazoo, Grand Rapids, and Flint. The areas of
8 focus include transformers on circuits in communities with above average MiEJScreen
9 scores that had multiple outages from 2021 through 2023 (targeted work is in census tracts
10 that are at least at the 60th percentile per MiEJScreen, with much of it at the 80th percentile
11 or higher).

12 This project work is estimated to save 288,000 customer-outage-minutes annually,
13 based on an estimated 80% reduction in outages on the secondary circuits and services
14 feeding homes.

15 **Q. Please provide more details regarding the work that will be done related to the grant**
16 **under Section 40101(c) of the IIJA.**

17 A. The purpose of this grant will be to use AI modeling in innovative ways to create value for
18 customers in historically disadvantaged communities and in areas of high DER penetration.
19 Specifically, the Company would deploy 18,000 distributed AI modules on residential
20 electric meters. These AI modules can quickly analyze high volumes of data to detect and
21 classify anomalies, and improve management of distributed assets, which will be
22 particularly valuable in locations with higher EV penetration. Locations would be selected
23 based on:

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- 1 a) circuits with reliability issues; and
- 2 b) circuits and transformers with DER penetration.

3 For this project, the Company will work with General Motors, Utilidata, EPRI, and

4 the University of Michigan Transportation Research Institute. The Company is not yet

5 seeking rate recovery of any costs related to this grant.

6 **Q. Will the Company continue to seek recovery of costs or provide refunds for funding**

7 **awards related to IIJA projects?**

8 A. As discussed earlier in my testimony, the Company is accounting for the costs of the

9 projects, and the offsetting awards from the federal government, as shown in my capital

10 exhibits.

11 The Company will continue to seek the use of a regulatory asset or liability to defer

12 the revenue requirement of IIJA funding expenses above or below amounts included in

13 rates, in accordance with the Commission's guidance in Case No. U-21227, for projects

14 the Company has applied for but has not yet received notification of a selection decision

15 from the federal government.

16 **Q. How will the Company continue to update the Commission on its continued efforts to**

17 **pursue IIJA funding for distribution-related projects?**

18 A. The Company will continue to update the Commission biannually in Case No. U-21227,

19 most recently on December 30, 2024. The next update is planned to be filed on June 30,

20 2025. Further biannual updates are planned to be filed on December 31 and June 30 of

21 every year until further ordered by the Commission, or until all applicable funding

22 opportunities under IIJA are closed to applications.

1 **Q. What information is included in the biannual updates?**

2 A. The biannual updates include a narrative summary of which opportunities the Company
3 applied for, including citations to individual programs sought, what stage of the grant
4 process that application is in, which applications have been approved and awarded funding,
5 and others that may be in process.

6 **IV. CAPITAL SPENDING OVERVIEW**

7 **Q. How does the Company ensure that its electric distribution capital planning process**
8 **selects the correct alternatives?**

9 A. The Company is committed to making investments in its distribution system to ensure they
10 will deliver clear and cost-effective customer benefits, and not just making investments for
11 their own sake. For traditional investments on the distribution system, the Company
12 generally uses a “least--cost, best-fit” analysis to identify the optimal project. When an
13 asset has failed, or is in poor health and at risk of failing, or if it is projected to be
14 overloaded soon, or must be relocated, the Company has no alternative but to address the
15 issue to ensure customers continue receiving reliable service. The Company identifies the
16 least costly solution that will satisfactorily solve the issue. The Company has used more
17 extensive benefit-cost analyses for some non-traditional investments.

18 **Q. What do you mean by “traditional” and “non-traditional” investments?**

19 A. In the context being used here, the Company defines “traditional” distribution investments
20 as investments in components of lines (such as poles, pole tops, conductor, and certain
21 devices), substation infrastructure, and other related items, across a variety of investment
22 programs. Conversely, the Company defines “non-traditional” distribution investments as
23 those in newer technologies, such as those covered in Grid Automation, or in certain pilot
24 programs.

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1 **Q. Can you provide more detail regarding how “least-cost, best-fit” analysis works?**

2 A. Yes. The overarching principle of least-cost, best-fit (“LCBF”) is that once the Company
3 has identified an issue on the distribution system that must be addressed, the Company
4 identifies and chooses a solution that satisfactorily fixes the issue for the least cost.

5 The identified issue may be a failed piece of equipment, a circuit or subset of a
6 circuit with persistently poor reliability, an overloaded piece of equipment, an asset that
7 must be relocated, or any number of other issues. LCBF analyses ensure investments are
8 both cost-effective and meet the necessary functionality and capability requirements.

9 LCBF analyses themselves are not necessarily used to rank and prioritize projects
10 against one another. As discussed elsewhere in testimony, particularly by Company
11 witnesses Partlan and Hayward, the Company prioritizes the assets that need to be
12 addressed based on a variety of inputs, depending on the specific investment program.
13 Once assets have been prioritized and the Company has determined where work is needed,
14 LCBF is used to select the type of project to execute in that location.

15 LCBF is commonly recognized in the utility industry as an appropriate means for
16 evaluating traditional reliability investments. It is important to note that LCBF does not
17 always lead to the Company selecting the lowest cost alternative outright, because the “best
18 fit” part of the principle must also be considered.

19 **Q. In identifying a solution, how does the Company compare different potential projects**
20 **against one another?**

21 A. For some smaller projects, the Company may identify a solution based on what has been
22 known to work in similar circumstances in the past, applying the least-cost, best-fit
23 principles discussed above. For many larger projects, the Company uses a more formal

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1 process to compare proposed electric distribution investment against alternatives,
2 developing a “concept approval” to test and demonstrate why the selected project is
3 reasonable and prudent, ensuring strong and robust justification for selected electric
4 distribution projects.

5 For example, concept approvals for the Company’s top 25 distribution projects are
6 provided with Part III Requirement 142 in this case. The general structure of a concept
7 approval includes the following:

- 8 1. Identification of the problem;
- 9 2. Identification of alternatives to address the problem;
- 10 3. Determination of costs and benefits of the alternatives;
- 11 4. Selection of best alternative;
- 12 5. Approvals; and
- 13 6. Revisions, if necessary (i.e., if costs and/or project scope change substantially
14 following approval).

15 **Q. Please explain the Company’s process for concept approvals.**

16 A. The process begins by the Company’s planning engineers identifying problems (such as by
17 reviewing reliability data and projected overloads) and system needs (such as by reviewing
18 customer or third-party requests).

19 Once the problems or needs are identified, the planning engineers develop a list of
20 alternative solutions. For each alternative, costs, benefits, and intangible considerations
21 are developed. Although the planning engineer is responsible for this process, there is
22 significant collaboration with design engineering, construction, and operating personnel in
23 each phase of the process.

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1 The alternatives are then compared against each other, and the planning engineers
2 identify a selected alternative. The Company identifies selected alternatives using an
3 LCBF, as discussed above. In other words, investment that yields the best fit is intended
4 to produce the maximum benefit at the least cost. This ensures the Company's investment
5 is optimized for customer benefit.

6 The final step of the process is to document all the information in a concept
7 approval document that is routed through management for approval. In most cases, concept
8 approval documents go to a program manager for review and approval, but could require
9 additional approvals, depending on the projected cost of the project.

10 **Q. Please provide an illustrative example of the concept approval process.**

11 A. Au Gres Township passed a medical marijuana ordinance in 2018 resulting in five
12 customers requesting electric service for marijuana grow facilities totaling 2.8 megavolt
13 amperes ("MVA"). The electric system in that area was not capable of supporting an
14 incremental 2.8 MVA of demand.

15 In response to these requests, the Company's planning engineers reviewed the
16 surrounding electric system to determine conceptual alternatives for serving the
17 incremental demand. The concept approval document included four alternatives involving
18 different locations for substations connected at different voltage levels.

19 For each alternative, the Company developed a projected cost, feasibility, and
20 timeline based on performing similar work in the past. In addition to the costs, the
21 Company's planning engineers examined other considerations for each alternative,
22 including availability of ROW, reliability impact, and ability to meet timeframes requested
23 by the customers.

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1 A selected alternative was identified that represented the best fit project to provide
2 reliable service to the Au Gres area. The problem statement, alternatives, and selected
3 alternative were documented in the Company's concept approval form and routed to
4 management for review and approval. Once approved, the selected alternative was
5 commissioned for ROW acquisition, and substation and line design and construction.

6 Soon after commencing work on the selected alternative, ROW challenges and new
7 customer load requests totaling 6.8 MVA necessitated a revision to the selected alternative
8 as it was apparent the originally selected alternative was no longer viable at the approved
9 cost. Additionally, easements for a new 138 kV line were unable to be obtained along the
10 proposed route, and it was determined a significant number of wetlands were present in the
11 area. Lines passing through wetlands require a lengthy permitting process and often costly
12 mitigation work. A revised concept approval with this new information and costs was
13 needed.

14 The revised concept approval document showed the changes from the original
15 document to concisely convey them to management. These changes included updating the
16 problem statement, including new or revised alternatives, and refining the costs and
17 benefits. The revised concept approval followed the same process as the original, with the
18 Company's planning engineers developing alternatives, costs, and benefits, and then
19 seeking management approval of the selected alternative.

20 The newly included fifth alternative for the Au Gres area was the selected
21 alternative because it was a solution to both serve the new incremental customer demand
22 and improve reliability to the area.

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1 The revised concept approval and selected alternative did not pass through the
2 approval process without questions. Discussions between management and planning
3 engineers led to the identification of improvements within the selected alternative.
4 Specifically, the circuit configuration was refined to further improve reliability to the area
5 customers. These circuit configuration improvements were included in the concept
6 approval for documentation purposes, but the selected alternative did not change.

7 The revised concept approval was ultimately approved, and the newly selected
8 alternative was commissioned for ROW, design, and construction.

9 **Q. How do customers benefit from the concept approval process?**

10 A. The concept approval process provides a rigorous approach and governance structure to
11 identifying problems and needs, alternative solutions, and recommended alternatives. It
12 provides for exceptional peer review and management oversight to ensure the Company's
13 investment plans are well justified, reasonable, and prudent for customers.

14 **Q. Does the Company use any other regular practices to identify areas of the system that**
15 **require prioritized investment?**

16 A. Yes. The Company has also implemented a Distribution System Health Quarterly
17 Operating Review ("QOR"). The QOR allows Company planners to go through a
18 comprehensive review of the entire system, reviewing asset health of system components
19 based on information gathered during inspections and maintenance activities. Gathered
20 data informs the Company on an asset's health based on likelihood, consequence, and
21 severity of an asset's failure, also known as that asset's risk. When assets are identified as
22 being at-risk, the Company develops projects to address that risk proactively. The QOR

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lets the Company monitor shifts in asset risk and ensures continued investment in the correct places based on the latest asset information.

By reviewing asset health data every quarter, the Company has the most up-to-date information on what investments will be needed (and how much investment will be needed) as projects are planned for the following few years.

The Company continues to make improvements to its QOR process so the review process provides increasingly better information. Company witness McPhail's projected Distribution Asset Management investments are crucial for these ongoing improvements.

Q. How does the Company classify its distribution capital investments?

A. The Company makes capital investments under two broad classifications, *unplanned* and *planned*, as outlined in Figure 29 below.

FIGURE 29
PLANNED AND UNPLANNED DESCRIPTIONS

Classification	Description	Programs included
Planned	Investments planned to proactively improve grid reliability through capacity upgrades, and investments in new tools and technology.	Reliability, Capacity, "Electric Other," Wildfire Risk Mitigation
Unplanned	Demand-driven, customer-driven, or other reactive needs.	New Business, Demand Failures, Asset Relocations

Each of these classifications correspond to one or more capital "Programs," and they are:

- Reliability;
- Capacity;
- New Business;
- Demand Failures;
- Asset Relocations;
- Electric Other;

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- Vulnerable Communities Resiliency Plan; and
- Wildfire Risk Mitigation.

Each Program is in turn divided into several “sub-programs,” and many sub-programs are divided into several “investment categories.”

Programs can include spending on LVD, HVD, and Metro assets, but each sub-program and investment category is specific to a single asset classification. Company witnesses Partlan, McPhail, and Hayward each explain how investments are broken into sub-programs and investment categories under the seven overall programs identified here.

Q. What work is completed in the Reliability Program?

A. The purpose of the Reliability Program is to ensure the long-term safe and reliable operation of the distribution system, particularly by reducing system outages and hardening the system. This includes installing, upgrading, and rehabilitating LVD and HVD lines, LVD and HVD substations, Metro underground assets, and protective relay systems; it also includes investments to modernize the grid through Grid Automation.

Reliability Program investments are a major contributor to the Company’s efforts to address deterioration. While other programs may replace deteriorated assets as a secondary consideration, many Reliability investments have the express purpose of doing so. Grid Automation investments are included in the Reliability Program because many of the automation capabilities delivered by Grid Automation improve reliability for customers. As discussed above, the Company is planning an increase in investment in the Reliability Program under the plan outlined in the Reliability Roadmap.

Q. What work is completed in the Capacity Program?

A. The Capacity Program is designed to:

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1. Ensure that the HVD system can serve forecasted peak demand when all HVD facilities are in service;
2. Ensure that individual HVD facilities can be taken out of service during non-peak period without loading equipment beyond ratings or providing unacceptably low voltage;
3. Address LVD equipment overloads that have occurred; and
4. Proactively address LVD equipment that has run at a higher loading than rated for.

Additionally, the Capacity Program includes the CVR sub-program that puts that component of the Company's IRP into effect.

Q. What work is completed in the New Business Program?

A. The New Business Program includes the capital costs of connecting new commercial, industrial, and residential customers to the Company's distribution grid. This includes the costs of installing poles, conductor, transformers, meters, and in some cases, entire new substations. Because of the Company's obligation to serve customers, the Company generally is required to provide the requested interconnections if the customer meets the requirements set by the Company's tariffs.

Q. What work is completed in the Demand Failures Program?

A. The Demand Failures Program addresses issues related to customer interruptions or failures of equipment on the system. When equipment fails and customers are interrupted, the Company is obligated to fix the issue and restore customers as quickly as possible. The program also enables the Company to respond to day-to-day equipment failures, even if customers may not be interrupted. If the Company fixes failed equipment in this process, the capital expenditures take place in the Demand Failures Program.

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1 **Q. What work is completed in the Asset Relocations Program?**

2 A. The Asset Relocations Program includes capital investments to relocate electric assets to
3 accommodate road, building, and other third-party construction projects, including those
4 requested by municipal governments, as well as internal Company projects.

5 **Q. What work is completed in the Electric Other Program?**

6 A. The Electric Other Program consists of additional capital investment to support the
7 distribution system that does not fall into one of the other five programs.

8 **Q. What work is completed in the Vulnerable Community Program?**

9 A. This line item in my exhibits represents the work being done in the Vulnerable
10 Communities Resiliency Plan that I described earlier in my direct testimony.

11 **Q. What work is completed in the Wildfire Risk Mitigation Program?**

12 A. The Wildfire Risk Mitigation Program is aligned with the Company's wildfire risk
13 mitigation strategy that I described earlier in my direct testimony. In the instant case, the
14 Company is not requesting recovery of any capital investment for the Wildfire Risk
15 Mitigation Program, although the Company is seeking recovery of some O&M expenses.

16 **Q. Referring back to Figure 29, please describe unplanned investments.**

17 A. Several of the Company's capital investment programs respond to demand-driven,
18 customer-driven, or other emergent needs. These investments are not strictly "unplanned,"
19 as the Company does anticipate it will have to make these investments to replace failed
20 equipment, and to add new customer connections to the system. However, due to the
21 emergent nature of these needs, the Company's investments can be difficult to plan with
22 specificity in advance, because it is not possible to know the exact number of equipment
23 failures that will occur or new customer connection requests that will occur, or where such

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1 needs will occur. Instead, the Company forecasts the number of new business services that
2 will be requested in the future based on historical service levels and projected growth rates,
3 as further discussed in Ms. Partlan's direct testimony. The Company then applies a unit
4 cost to these expected requests to develop a forecasted level of spending. These unplanned
5 programs consist of New Business, Demand Failures, and Asset Relocations.

6 **Q. Please describe planned investments.**

7 A. In addition to the investments addressing emergent needs described above, the Company
8 also plans investments further in advance to proactively improve the grid through reliability
9 improvement projects, capacity upgrades, and investments in new tools and technology.
10 These programs consist of Reliability, Capacity, Electric Other, and Technology.

11 **Q. Are all investments in the planned programs identified and planned equally far in**
12 **advance?**

13 A. No. Individual projects vary widely in size, scope, cost, complexity, and other factors, and
14 they correspondingly vary in how far in advance they are planned. For example, on the
15 HVD system, substation and line rebuilds are large, complex projects with long lead times
16 for design and construction work, so those projects are planned more than a year in
17 advance. Conversely, individual pole replacements on the HVD system are comparatively
18 simple, with lead times in the order of weeks, so the Company does not identify individual
19 poles for replacement months or years in advance; instead, the Company identifies HVD
20 lines on which it will inspect poles in advance, with an expectation that, based on historical
21 inspection experience, a given number of poles inspected will require replacement.

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1 **Q. What capital projects does the Company expect to invest in during the bridge period**
2 **and the test year?**

3 A. Specific distribution projects for the bridge period and test year are discussed by Company
4 witnesses Partlan, Hayward, and McPhail, and are identified in their exhibits.

5 **Q. What information is included in these exhibits?**

6 A. The exhibits include projects identified with scope, cost, location, benefit type, and
7 benefits. Figure 30 below identifies quantifiable benefit types.

FIGURE 30
INVESTMENT BENEFIT DESCRIPTIONS

Benefit Type	How Benefits were Quantified
Customer-outage-minutes	Product of the number of customers that experience an extended outage of electrical service and the duration of outage measured in minutes.
Customers Impacted	Number of customers served by a project. In the case of commercial customers, the customers impacted are treated as “1.”
NOTE: Not all projects have quantifiable benefits. Some projects in the Capacity, Reliability, and Electric Other programs are completed for regulatory compliance, operating efficiency, or based on the Company’s obligation to serve.	

8 **Q. What is meant by a “Customer-Outage-Minute” benefit?**

9 A. *Customer-outage-minutes* (sometimes referred to as customer minutes interrupted or
10 “CMI”) is a mathematical product of the number of customers that experience an extended
11 outage of electrical service, and the duration in minutes of that outage. These numbers are
12 gathered through the Company’s outage management systems for each outage. For
13 example, a failure on the LVD system that interrupts electrical service to 100 customers
14 for 170 minutes would accrue 17,000 customer-outage-minutes.

15 A reliability project will reduce this number by reducing the probability of failure
16 leading to an outage, the duration of the outage, and/or the number of customers impacted

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1 by the failure and subsequent outage. The planning engineer will determine the amount of
2 savings based on both the historical outage data of that part of the system and the expected
3 effectiveness of the solution selected. For example, if the historic average customer-outage-
4 minutes of an LVD zone were 20,000 per year and the proposed project would reduce the
5 probability of that outage by 70%, the customer-outage-minutes saved or avoided by
6 completing the work would be 14,000 (70% of 20,000). In this way, the benefit of a
7 distribution reliability project can be quantified.

8 **Q. How do the Company's projected customer-outage-minutes in the instant case**
9 **compare to the Company's SAIDI levels or projections about SAIDI in the future?**

10 A. While there may be an indirect connection between customer-outage-minutes avoided and
11 SAIDI, they are two separate things and should not be conflated. Customer-outage-
12 minutes avoided is a way to model the future outages that *would likely* occur on a circuit,
13 line, or substation if a project is not done and the asset were to fail. For some assets,
14 especially substations, historical outages are generally infrequent, meaning their historical
15 contribution to SAIDI is relatively low, and projects will not necessarily significantly
16 decrease SAIDI in the future. However, substation failures are high-impact events when
17 they do happen, so a substation project may have a high number of customer-outage-
18 minutes avoided, because the project prevents a future failure and therefore prevents many
19 future outages that would have otherwise happened.

20 In general, for any type of asset, investments to reduce the likelihood of future
21 outages do have a large impact on the projected number of future customer interruptions
22 that would happen absent the investments. For example, if the Company assesses that a
23 transformer is at risk of failure, and failure would cause 10,000 customers to lose power

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1 for 24 hours, the Company will conclude that replacing the transformer avoids those
2 outages in the future, which is a reasonable assessment even if there have not yet been
3 actual historical outages to consider. By considering projected customer-outage-minutes
4 avoided in this manner, the Company can meaningfully compare the relative benefits of
5 different potential projects.

6 **Q. What is meant by a “Customers Impacted” benefit?**

7 A. *Customers impacted* is the number of customers who are served by an asset or project and
8 therefore would experience an outage of electrical service if this asset were to fail or would
9 realize a benefit to reliability with its improvement.

10 **Q. Does the Company propose to receive deferred accounting authorization in this case**
11 **for the New Business, Demand Failures, and Asset Relocation programs?**

12 A. Yes. While the Company attempts to project investment needs for the New Business,
13 Demand Failures, and Asset Relocations programs, the largest factors influencing
14 expenditures in these programs are externally driven. As a result, the Company requests
15 that it be allowed to continue to defer the revenue requirement for any capital spending for
16 these programs above what is included in rates, if the spending exceeds what the
17 Commission approves in this case. The Company agrees to the same stipulations the
18 Commission approved for deferred accounting treatment for these programs in Case No.
19 U-21585. One of the stipulations is that the Company spend the full amounts approved by
20 the Commission in the Line Clearing Program. As further described in the direct testimony
21 of Company witness Stewart, the Company is proposing a “ramp-up” to achieve a five-year
22 clearing cycle on the LVD system. Ms. Stewart bifurcates the total Line Clearing Program
23 expenses between “total” and “baseline” O&M expenses. For purposes of the

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1 aforementioned stipulation, the Company requests that the threshold be set on the
2 “baseline” Line Clearing O&M expenses supported by Ms. Stewart.

3 **Q. What risks would be created if deferred accounting were not authorized in the instant**
4 **case?**

5 A. If deferred accounting is not authorized for any spending in New Business, Demand
6 Failures, and Asset Relocations that exceeds what the Commission approves, then the
7 Company will be exposed to financial risk if increased investment needs materialize in
8 those programs. Investment in all three programs is heavily driven by external factors,
9 including customer requests the Company must address. Although the Company makes
10 reasonable and best efforts to project investment needs in those programs, they cannot be
11 projected with complete accuracy. As an illustrative example, the Company could project
12 test year Asset Relocations investments of \$50 million, based on a well-supported
13 methodology, and the Commission could approve this amount for inclusion in rates. When
14 the test year arrives, new and unforeseen Asset Relocations needs could emerge, driven by
15 external factors, such that total Asset Relocations investments now total \$55 million. In
16 this hypothetical, the Company must make the incremental \$5 million in investments.
17 When deferred accounting is authorized, the Company has certainty that this incremental
18 \$5 million will be recoverable, even if on a deferred basis.

19 Conversely, without deferred accounting, this \$5 million would be at risk. The
20 Company must complete the Asset Relocations, but to keep overall investment levels in
21 line with Commission approval, the Company would need to delay \$5 million in
22 investments in one of the planned programs, such as Reliability or Capacity. This would
23 deprive customers of the benefits of those programs.

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1 Furthermore, the Commission has not always approved 100% of the Company's
2 projected investment amounts in these three programs for a variety of reasons.

3 If other parties argue the Company's projected investment levels in these programs
4 are too high and the Commission agrees in a final Order, then deferred accounting supports
5 recovery if investment levels materialize as the Company forecasted.

6 Deferred accounting has been approved by the Commission (through both approved
7 settlements and orders in fully contested cases) in every rate case since Case No. U-20134,
8 which covered a 2019 calendar test year. Since that time, deferred accounting has worked
9 to provide for recovery of externally-driven investments that must be made and ensure the
10 Company does not need to reduce investments in other programs that focus on proactively
11 improving customer reliability.

12 **Q. How did the Company identify areas of distribution investment to include in the IRM**
13 **in this case?**

14 A. The Commission provided partial approval of the Company's proposed IRM in Case No.
15 U-21389, for a two-year period that will end on February 28, 2026. In the instant case, the
16 Company is proposing to establish a continuing mechanism that will extend the IRM for
17 an additional two years, consisting of the test year in the instant case and the year after that,
18 meaning the continuing IRM would run until April 30, 2028. In the instant case, the
19 Company is proposing to continue the IRM using the same investment categories the
20 Commission approved in Case No. U-21389, and to add two new sub-programs, as
21 discussed below. For all proposed IRM spending, the Company proposes to set the
22 investment levels for those categories at or below those included in the test year in the

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1 instant case. See also the discussion of the IRM in Company witness Myers' direct
2 testimony.

3 **Q. What investments are included in the proposed IRM?**

4 A. The IRM investments previously approved by the Commission consist of the following
5 sub-programs:

- 6 • *LVD Lines Reliability* - Targeted Circuit Improvements and Pole Replacements;
- 7 • *Resiliency* - Fractionalization; and
- 8 • *System Protection*.

9 In the instant case, the Company is proposing to also include the Repetitive Outages
10 sub-program and the Vulnerable Communities Resiliency Plan in the IRM.

11 **Q. Why is the Company proposing to include the Repetitive Outages sub-program in the**
12 **IRM?**

13 A. As discussed by Company witness Partlan, the Company's recent performance for CEMI-4
14 has not been meeting the Commission's Service Quality and Reliability Standards, and will
15 not meet the standard at current investment levels. The Repetitive Outages sub-program
16 is specifically designed to identify locations on the system where customers experience
17 frequent outages and correct the underlying issues. The Company is proposing to increase
18 investment in this sub-program, and including the expenditures in the IRM will provide
19 additional assurance to the Commission and to customers that these funds will be spent on
20 improving CEMI-4 to the Commission's standards.

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1 **Q. Why is the Company proposing to include the Vulnerable Communities Resiliency**
2 **Plan in the IRM?**

3 A. As discussed earlier in my direct testimony, the Vulnerable Communities Resiliency Plan
4 is crucial for ensuring disadvantaged communities in the Company's service territory
5 receive better than average all-weather reliability.

6 Including this spending in the IRM will provide assurance these expenditures will
7 be directed to this important goal. Furthermore, in its final Order in Case No. U-21389,
8 the Commission expressed a desire that any IRM should see investments deployed
9 equitably, and that an IRM should not "exacerbate or perpetuate racial or socioeconomic
10 disparities in service."¹⁸ Including the Vulnerable Communities Resiliency Plan in the
11 IRM will support this goal.

12 **Q. What level of expenditure does the Company propose to include in the IRM?**

13 A. Based on this discussion above, the proposed expenditure level is as follows:

FIGURE 31

PROPOSED IRM EXPENDITURES

Sub-Program/ Investment Category	Proposed IRM Expenditure
Lines Reliability – LVD <i>(Targeted Circuit Improvements and Pole Replacements)</i>	\$276,191,000
Resiliency – Fractionalization	\$11,647,000
System Protection	\$4,098,000
Repetitive Outages - LVD	\$30,344,000
Vulnerable Communities	\$30,000,000
Total	\$352,280,000

¹⁸ MPSC Case No. U-21389, March 1, 2024 Order, page 273.

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1 **Q. How do these proposed IRM expenditure levels compare to what was approved by**
2 **the Commission in Case No. U-21585?**

3 A. The proposed IRM expenditure levels for LVD Lines Reliability are greater than those
4 approved by the Commission in Case No. U-21585, in line with the Company's total
5 proposed test year investment amount in the instant case. LVD Repetitive Outages is newly
6 proposed for inclusion in the IRM in the instant case, and the Vulnerable Communities
7 Resiliency Plan is a newly proposed investment altogether. The proposed IRM expenditure
8 levels for Resiliency and for System Protection are lower than the amounts approved by
9 the Commission in Case No. U-21585. This lower amount is due to project selection for
10 the test year in the instant case; the Company's identified projects in these two
11 sub-programs, in total, require less funding than those included in Case No. U-21585.

12 **Q. What metrics will the Company track in the IRM?**

13 A. The Company plans to continue tracking the same metrics as those included in Case No.
14 U-21389, plus an additional metric for Repetitive Outages, and report them to the
15 Commission annually.

FIGURE 32
PROPOSED IRM METRICS

Sub-Program	Proposed Metric(s)
Lines Reliability - LVD	• Miles of Targeted Circuit Improvements • Fuse Locations • LVD poles replaced
Resiliency	• Fractionalization projects completed
System Protection	• Relays installed
Repetitive Outages - LVD	• Zones Improved
Vulnerable Communities	• Miles of Vulnerable Communities Resiliency Plan projects completed

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1 **Q. What dollar amounts, and number of projects, did the Company plan to perform**
2 **during the first year of the IRM, covering the period from March 1, 2024 to**
3 **February 28, 2025?**

4 A. For the first year of the IRM, covering the period from March 1, 2024 to February 28, 2025,
5 the Company planned to perform the number of projects with the associated dollar amounts
6 listed in Figure 33.

FIGURE 33
YEAR 1 IRM: TARGETED METRICS AND APPROVED SPEND

Sub-Program	Performance Metrics	Target Units	Approved Spend
Lines Reliability	Miles of Targeted Circuit Improvements	50	\$36,880,000
	Lateral fuses added	7,000	
	LVD poles replaced	300	
Resiliency	Fractionalization projects	4	\$8,973,000
System Protection	Relay Panels Installed	16	\$3,473,000
Total			\$49,326,000

7 **Q. What dollar amounts, and number of projects, did the Company actually perform**
8 **during the first year of the IRM?**

9 A. The actual performance in dollar amounts and number of projects are listed below in
10 Figure 34.

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FIGURE 34
YEAR 1 IRM: ACTUAL METRICS AND ACTUAL SPEND

Sub-Program	Performance Metrics	Actual Units	Actual Spend
Lines Reliability	Miles of Targeted Circuit Improvements	56	\$52,817,000
	Lateral fuses added	8,524	
	LVD poles replaced	372	
Resiliency	Fractionalization Projects	1	\$7,992,000
System Protection	Relay Panels Installed	17	\$5,323,000
Total			\$66,132,000

1 **Q. Why did the Company not achieve the targeted spend in Resiliency?**

2 A. The Company experienced a series of delays in beginning the fractionalization projects in
3 the Resiliency sub-program, which ultimately hindered the ability to complete the entire
4 approved spending amount in the 12 months of IRM year 1. The fractionalization projects
5 in the Resiliency sub-program were delayed in securing easements and obtaining permits
6 in a timely manner. While these permitting delays did move the completion date of these
7 projects beyond the end of the first year of the IRM, all listed projects will be completed
8 during the 2025 calendar year, during the second year of the IRM. Further details are
9 provided as part of the Company's IRM reconciliation in Case No. U-21918.

10 **Q. Did the Commission discuss any considerations for the IRM?**

11 A. Yes. In its Order in Case No. U-21389, the Commission stated that it would review the
12 IRM and

13 "will consider, among other things, evidence presented on
14 whether the investments are, in fact, being deployed
15 equitably, whether the investments exacerbate or perpetuate
16 racial or socioeconomic disparities in service, whether there
17 has been a positive impact on reliability and resilience,

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whether there is sufficient opportunity for scrutiny of the investments, and whether customers have benefitted from the IRM mechanism.”

Q. How did the IRM positively impact reliability and resiliency?

A. The Company estimates the work completed drove improved performance as measured by SAIDI excluding MEDs of 3 minutes and All-weather SAIDI of 12 minutes while experiencing one less MED than in 2024.

Q. Did the Company deploy investments in an equitable manner?

A. Yes. The Company invested \$6,315,000 of the total \$66,132,000 spending, or 9.5%, in EJ communities. This IRM spending in EJ communities was greater than a proportional amount when considering the general make-up of the Company’s service territory. EJ communities consist of approximately 4.1% to 9.2% of the Company’s 1.9 million customers. The low-end customer count range of 4.1% represents the number of customers, approximately 78,000, living within the EJ-designated census tracts, while the high-end range of 9.2% represents the number of customers, approximately 175,000, served on the 2.5% of the Company’s 61,621 low voltage primary distribution circuit miles that provide service to EJ communities.

Q. Are there any additional benefits to the IRM?

A. The IRM serves as a way ensure proactive spending on projects that are beneficial to deliver a reliable and resilient system. By ring-fencing capital, it will not be diverted to other purposes, and if not spent, customers receive the benefit of a refund. Because the Company did not achieve the entire approved spend in Resiliency, customers will benefit from the refund discussed in Case No. U-21918.

1 **V. HISTORICAL SYSTEM PERFORMANCE**

2 **Q. How does the Company evaluate electric distribution system performance?**

3 A. The Company considers several reliability metrics, with SAIDI being the most prominent.
4 Other key reliability metrics measured and tracked by the Company include SAIFI, CAIDI,
5 and CEMI. Historical performance for these metrics is detailed in this section of my
6 testimony.

7 **Q. Why does the Company focus on SAIDI as part of its electric distribution spending?**

8 A. The importance of SAIDI performance was emphasized in a September 1, 2009 Report
9 addressed to the Michigan State Legislature, submitted on behalf of the MPSC, in
10 accordance with Section 10p of 2008 PA 286, MCL 460.10p, where it was stated:

11 In light of the research Staff conducted, the Commission
12 finds that Consumers Energy and Detroit Edison at this time
13 should include SAIDI, SAIFI, and CAIDI reporting (with
14 and without major events) on a rolling five year average in a
15 new docket that will be opened by the Commission. These
16 indices have been proven to show the reliability of electricity
17 in a utility's power system and are useful to the Commission
18 in identifying utility performance trends for each specific
19 utility on a going forward basis. The intent of the
20 information is not to benchmark the utilities nationwide or
21 within the state, but rather to measure performance levels of
22 each utility against its own historical data.

23 Additionally, in accordance with the September 15, 2009 Order in Case No.
24 U-16066, and a subsequent order in the same docket on January 23, 2014, the Company
25 provides the MPSC annual performance information related to SAIFI, CAIDI, and SAIDI
26 with and without MEDs, on a rolling five-year average, using the industry standard IEEE
27 method of calculation.

28 **Q. What are the components of SAIDI?**

29 A. SAIDI is comprised of two components: SAIFI and CAIDI.

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- SAIFI is a measure of frequency of outages that is driven by system condition, system configuration, and system challenges (i.e., weather).
- CAIDI is a measure of the duration of interruptions, and is driven by system condition, the number of interruptions, resource availability, and restoration management practices.

SAIDI is calculated as follows:

$$\text{SAIDI} = \text{SAIFI} * \text{CAIDI}$$

Figure 35 shows Consumers Energy's SAIFI results over the period of 2015 through 2024, excluding MEDs.

FIGURE 35
SAIFI (2015-2024) EXCLUDING MEDs

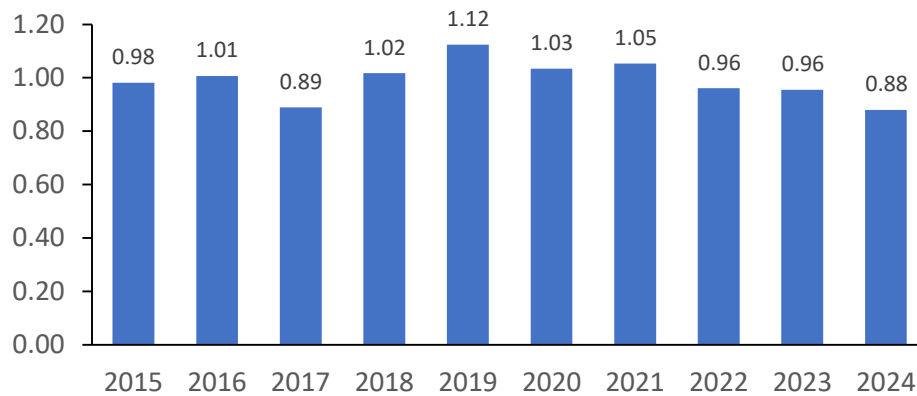
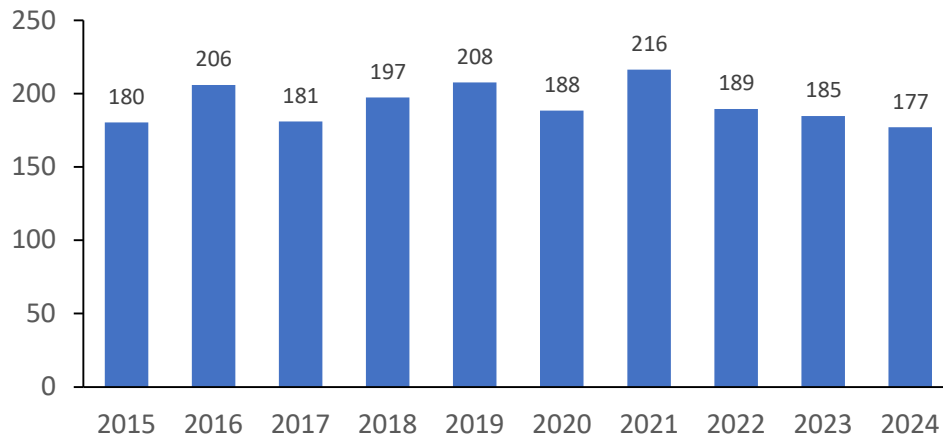


Figure 36 shows Consumers Energy's CAIDI results over the period of 2015 through 2024, excluding MEDs.

FIGURE 36
CAIDI (2015-2024) EXCLUDING MEDS

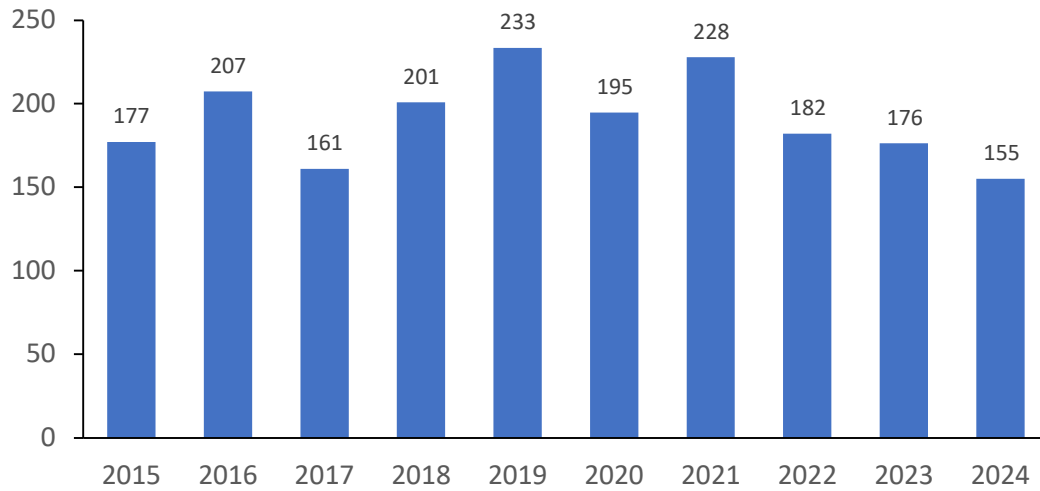


1 **Q. What has been the recent reliability performance of Consumers Energy’s distribution**
2 **system?**

3 A. Figure 37 below shows Consumers Energy’s SAIDI results, excluding MEDs,¹⁹ over the
4 period of 2015 through 2024. MEDs are excluded from these totals to normalize
5 performance data for unusually severe weather. The methodology for determining the level
6 of storm activity to exclude in developing this chart is based on the IEEE *Guide for Electric*
7 *Power Distribution Reliability Indices*.

¹⁹ IEEE Standard 1366-2012 defines the methodology for calculating a MED. It is based on a statistical analysis of five sequential years of daily values. In 2021, Consumers Energy adopted a refined methodology that transitions from a calendar day evaluation period to a rolling 24-hour evaluation period. This methodology better captures MEDs that straddle consecutive calendar days.

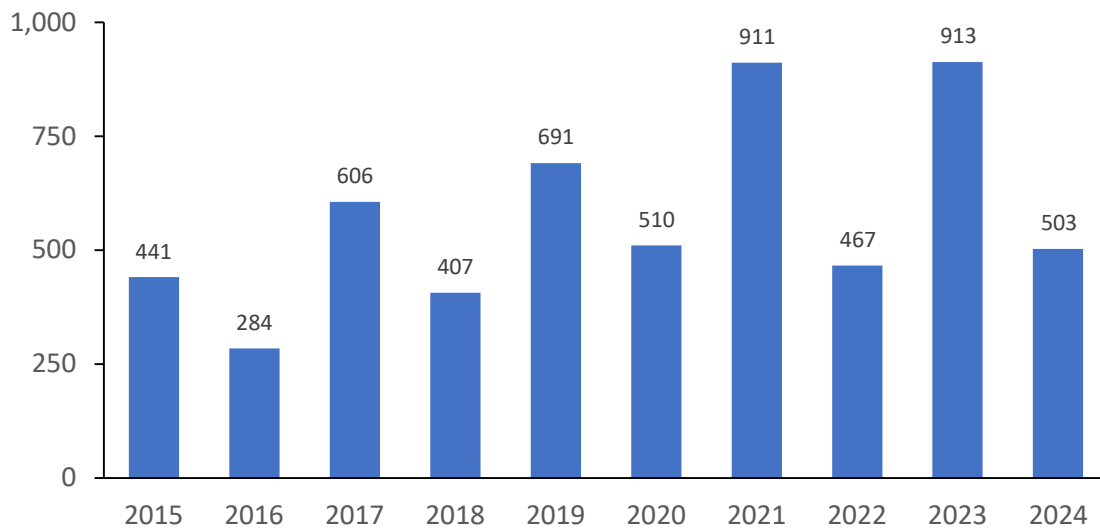
FIGURE 37
SAIDI (2015-2024) EXCLUDING MEDs



1 **Q. If MEDs are *not* excluded, what has been the Company's recent SAIDI performance?**

2 A. The Company's SAIDI results over the period of 2015 through 2024, *including* MEDs, are
3 shown in Figure 38 below.

FIGURE 38
SAIDI (2015-2024) INCLUDING MEDs



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1 **Q. Please explain the year-over-year variation in SAIDI when MEDs are included.**

2 A. The year-over-year variation is driven in part by the number of MEDs each year, as any
3 MED is likely to result in more customer outages than on a normal day. The number of
4 MEDs in each year from 2014 through 2023 is shown in Figure 39 below.

5 Storms in March 2017, July 2019, June 2020, August 2021, and February 2023 all
6 exceeded this threshold, and all translated into large increases in customer interruption
7 minutes, driving the higher annual SAIDI totals in those years. In most cases, these were
8 multi-day storms that resulted in consecutive MEDs.

9 Compared to the middle part of the last decade, the number of MEDs has been
10 consistently higher since 2017, an indicator of worsening weather and system deterioration.

FIGURE 39
MEDS PER YEAR, 2015-2024

Year	MED Days
2015	3
2016	5
2017	8
2018	7
2019	9
2020	8
2021	11
2022	9
2023	11
2024	10

11 **Q. What is the Company's forecast for CEMI performance through 2028?**

12 A. Absent the increased funding requested by Company witness Partlan for the Repetitive
13 Outage Program that is needed to achieve the MPSC's Service Quality and Reporting
14 Standards goal for CEMI-4, the Company would expect CEMI-4 performance as outlined
15 in Figure 40 below.

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FIGURE 40
CEMI-4 FORECAST 2025-2029

	2025	2026	2027	2028	2029
SAIFI (Including MEDs)	1.27	1.22	1.17	1.11	1.04
Percent of Customers at CEMI-4 or above	8.9%	8.2%	7.5%	6.7%	5.6%

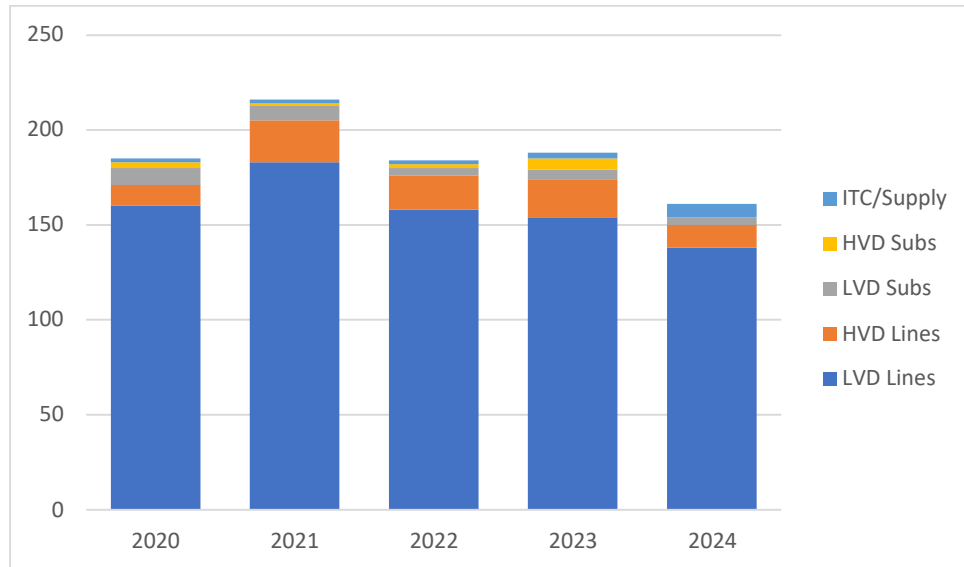
FIGURE 41
CEMI-4 FORECAST 2025-2029 WITH INCREMENTAL FUNDING

	2025	2026	2027	2028	2029
Percent of Customers at CEMI-4 or above	8.9%	6.0%	6.0%	6.0%	5.0%

Q. How is the Company's recent SAIDI performance broken down by system component?

A. Figure 42 below provides a breakdown of SAIDI by LVD lines, HVD lines, LVD substations, HVD substations, and the transmission system ("ITC").

FIGURE 42
SAIDI BY SYSTEM COMPONENT 2020-2024

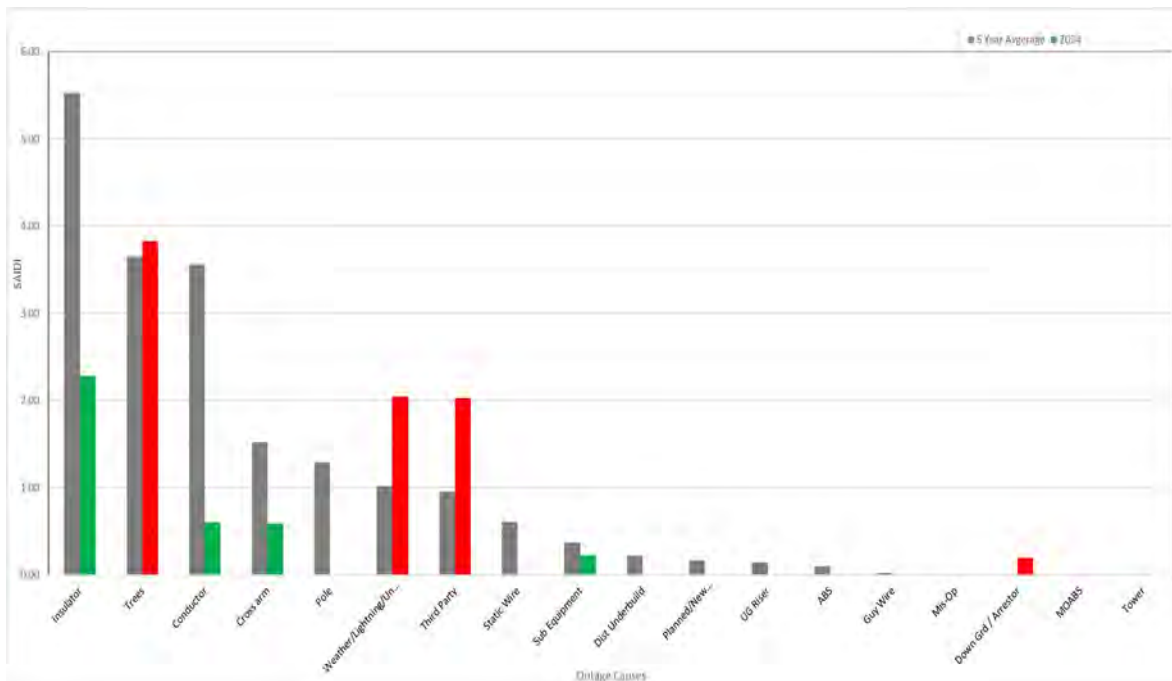


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Figure 43 through Figure 45 below show the top causes of outages for HVD lines, LVD lines, and substations by illustrating the five-year average alongside the 2024 results for each cause category, with the five-year averages shown in descending order.

Green bars indicate that the 2024 results were better than the five-year average, while red bars indicate that they were worse.

FIGURE 43
HVD LINES SAIDI MINUTES BY OUTAGE TYPE



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FIGURE 44
LVD LINES SAIDI CAUSES

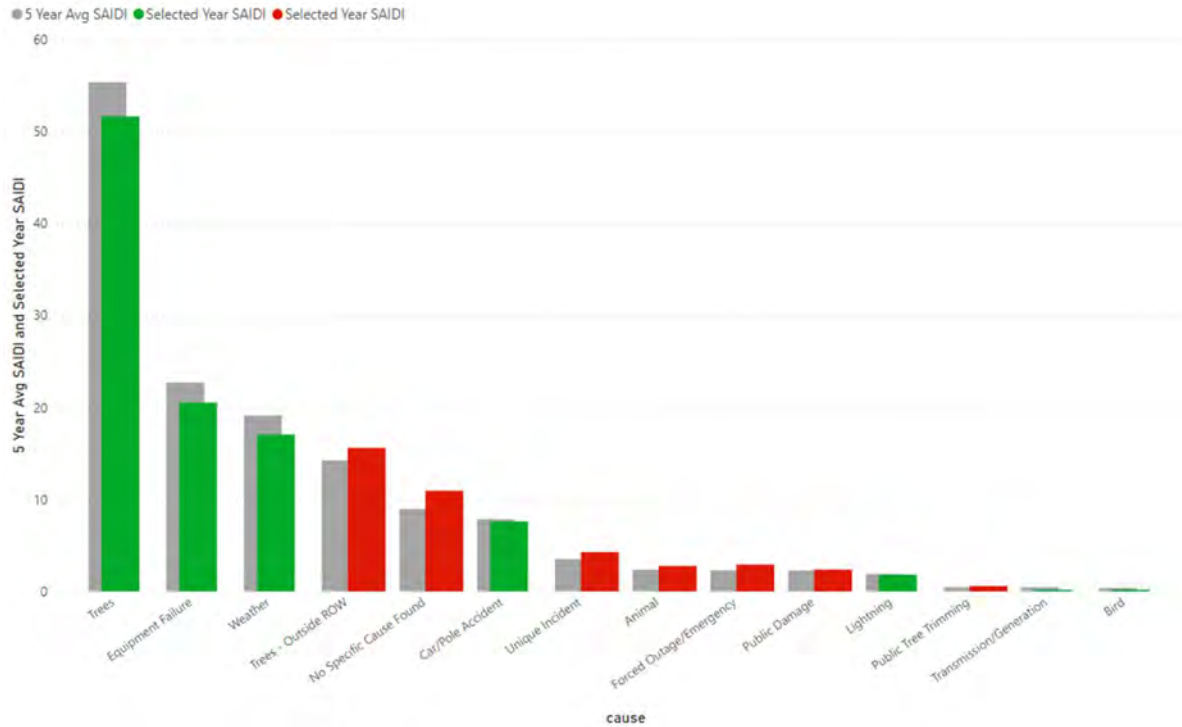
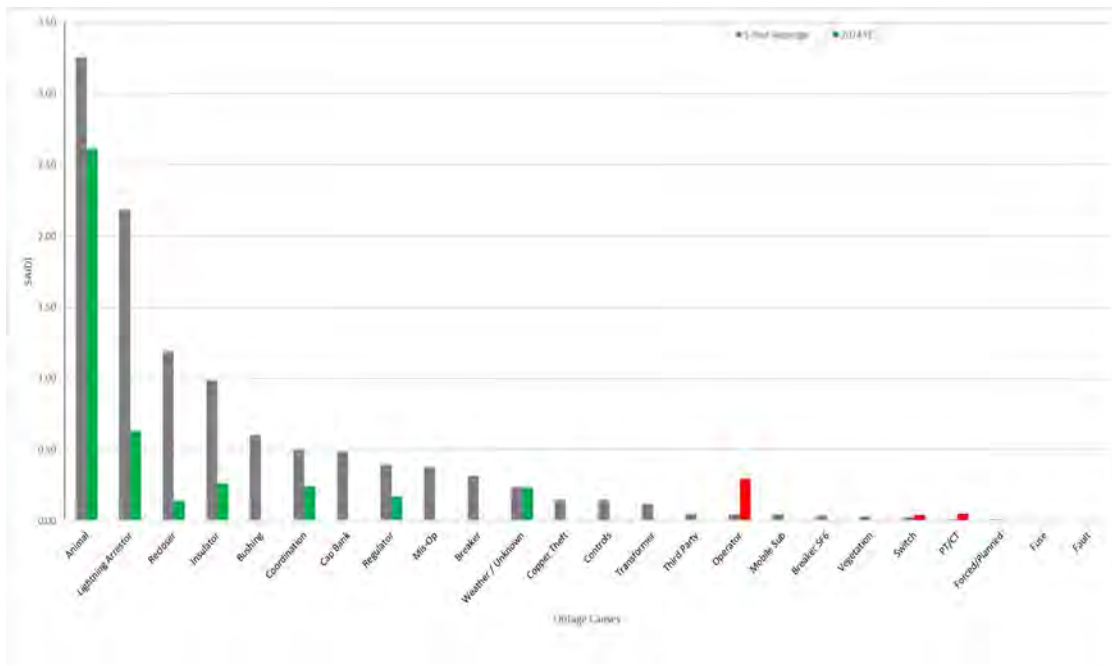


FIGURE 45
SUBSTATION SAIDI MINUTES BY OUTAGE TYPE



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1 **Q. Please describe the Company's recent experience with weather.**

2 A. The Company monitors wind speed data from 21 different official National Weather
3 Service stations in Michigan, as shown in Figure 46 below.

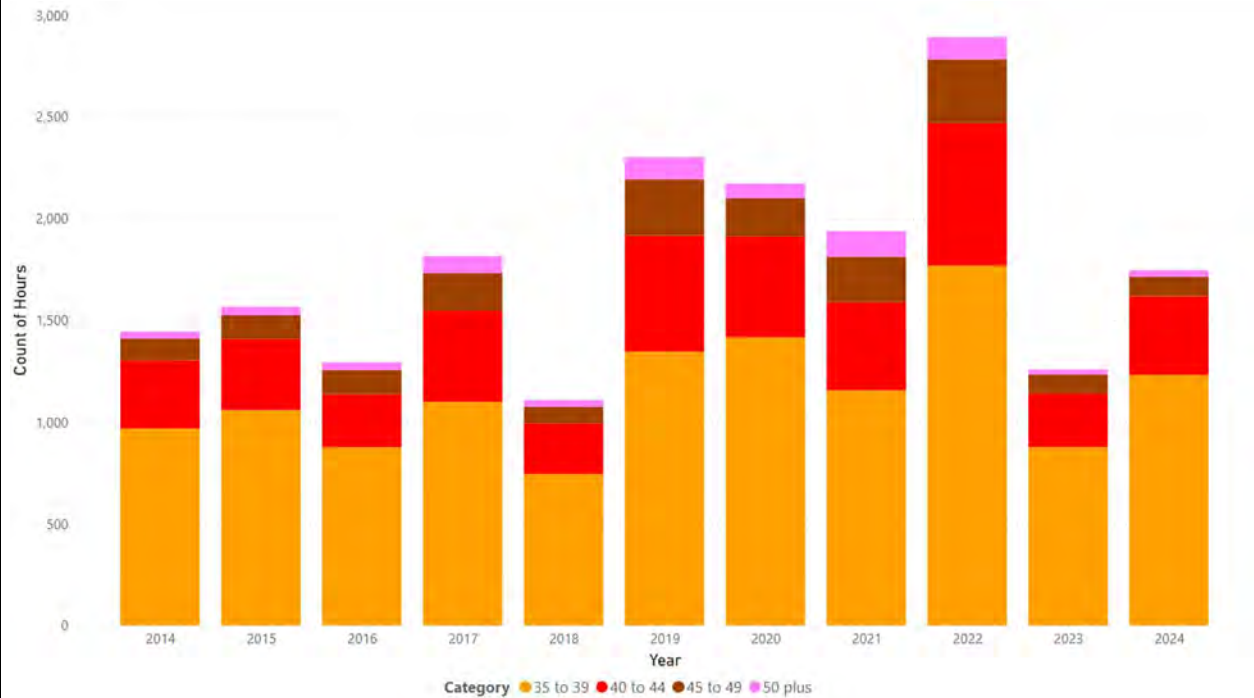
FIGURE 46
OFFICIAL NATIONAL WEATHER SERVICE WIND OBSERVATION STATIONS



4 In recent years, the Company has observed that wind speeds across the system have
5 increased in severity.

6 Figure 47 below illustrates the number of hours, aggregated across these
7 21 observation stations, during which wind speed was sustained at higher than 35 mph.
8 Sustained wind observations have generally been increasing over the past decade.

FIGURE 47
STATION HOURS EXCEEDING HIGH WIND SPEED THRESHOLDS



1 In terms of wind-caused outages, wind gusts can be even more damaging than
2 sustained high winds, given the often-violent nature of gusts.

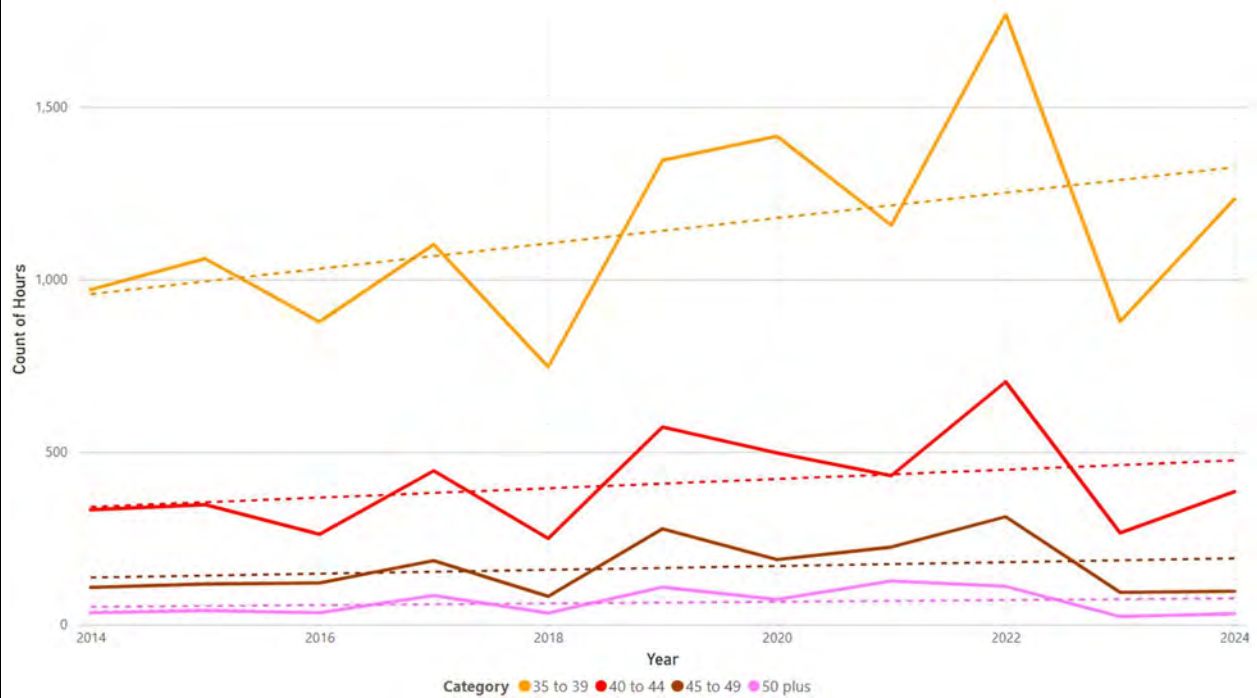
3 The National Weather Service observation stations record gusts when there are
4 rapid fluctuations of 10 knots (11.5 mph) or more between peaks and lulls over a 10-minute
5 window, with the gust speed being the maximum wind speed observed in that window.

6 Figure 48 below illustrates the number of hours, aggregated across the 21 stations,
7 during which gusts of more than 35 miles per hour were observed, isolating the frequency
8 of gusts exceeding 35 miles per hour in 5 mph bands.

9 As illustrated by the trend lines, gusts have been becoming more frequent at each
10 of the high-speed bands.

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FIGURE 48
STATION HOURS EXCEEDING HIGH GUST THRESHOLDS, 2014-2024



The data shown in Figure 47 and Figure 48 illustrates that wind speeds and gusts have been getting increasingly worse in recent years.

Q. What conclusions does the Company draw based on this wind speed data?

A. This data highlights that, as Michigan sees increasingly extreme weather, the electric distribution system needs to be hardened against that weather to improve resiliency. It is also important to note that wind gust data does not capture the full picture of severe weather; while 2023 was less gusty than other recent years, it did feature a major ice storm and several tornadoes that drove SAIDI.

1 **VI. TECHNOLOGY PROJECTS SUPPORTING ELECTRIC DISTRIBUTION**

2 **Q. Is the Company planning technology projects in the test year that support the**
3 **Company's electric distribution strategy?**

4 A. Yes. Company witness Stacy H. Baker is sponsoring:

5 a) the Electric GIS Utility Network Transformation project; and

6 b) the Electric GIS Design Platform Modernization project.

7 **Q. Please explain the Electric GIS Utility Network Transformation project.**

8 A. This project will transform the Company's current GIS platform to the Environmental
9 Systems Research Institute ("ESRI") Utility Network Model and establish a unified HVD,
10 LVD, and substations data model. This transformation aims to optimize core engineering
11 and operational processes, technologies, and data.

12 The Company's GIS for electric records is expanding as an authoritative source
13 for asset connectivity, location, and health information. However, growing business
14 requirements for advanced analytics and regulatory mandates necessitate more granular
15 geospatial insights. Existing functionality does not meet business partner needs, and GIS
16 data is refreshed in batch mode once a day, leading to mismatches with real-time systems.
17 Managing HVD and LVD data in different models remains challenging.

18 The Company's past implementation of ESRI's GIS for Electric, version 10.8.1,
19 will be unsupported after March 1, 2028. Critical third-party solutions supporting key
20 editing and business functionality are also ending support without upgrade options, posing
21 risks for security updates. ESRI's development focus is shifting to the ArcGIS Utility
22 Network Management extension, ArcGIS Enterprise, and ArcGIS Pro. The vendor's
23 development team has reached the limits of ArcMap and the geometric network's
24 capabilities and will no longer build additional functionality. Future development and

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enhancements are focused on the next-generation technologies of the Utility Network and ArcGIS Pro. ESRI utility solution partners are also moving their product lines away from the geometric network, soon supporting only the Utility Network.

The project scope includes:

1. Upgrading all database, web, and application servers to supported Windows version;
2. Upgrading end user application from ArcGIS Desktop to ArcGIS Pro;
3. Migrating and converting LVD and HVD GIS data from geometric network data schema to the Utility Network, iteratively publishing data to new model for consumption;
4. Reconfiguring electric applications that are integrated with GIS or that consume GIS data; and
5. Creating a substation asset model.

Q. What benefits will this project provide?

A. This project creates value for the Company by:

1. Mitigating risks associated with product support end of life;
2. Enabling detailed asset management and location-based analytics to bring clearer understandings around the assets that support energy delivery;
3. Increasing productivity through use of shortcuts, templates, and streamlined workflows within the software;
4. Providing extensive, out-of-the-box tracing tool;
5. Providing 3D visualization functionality;
6. Enabling users with editing tools, giving them guidance at every step of the process for developing workflows and enforcing stronger data integrity;
7. Viewing the up-to-date network in a map or schematic diagram and be able to quickly toggle back and forth between them; and
8. Enabling archiving and historical versioning to view the state of the electric network over time.

All these capabilities will result in greater insight and efficiency that improve the safety and delivery to customers. The Utility Network enables implementation of

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third-party tools that will allow us to keep the operational model more up to date as circuits with temp conditions and/or control tags can be imported as needed.

Q. What alternatives did the Company consider?

A. Alternatives considered included:

1. Continue to use geometric network. This alternative was not selected because the architecture is at the end of its life. Additionally, dependent third-party solutions are moving away from the geometric network, making it unsustainable for continued use.
2. Moving to Utility Network and migrating to a supported platform. This alternative was chosen to enable the Company to leverage a cloud-based solution and provide options for using third-party solutions.

Q. What is the cost of this project?

A. The Electric GIS Utility Network Transformation project requires \$1,324,225 in capital (\$1,059,380 ROM adjusted capital) and \$519,952 in O&M in the test year.

Q. How did the Company develop its projected expenditures for the Electric GIS Utility Network Transformation project?

A. The projected expenditures were estimated based upon previous work for that product family and anticipated software costs.

Q. Please explain the Electric GIS Design Platform Modernization project.

A. This project is replacing the existing design software for LVD with a new solution that will be fully integrated into the ESRI R GIS platform already in use by the Company.

This new solution will leverage GIS asset data to generate engineering designs. It will allow engineering teams to have a single source and format to view asset data, construction drawings, and redlines in both the back office and the field.

This change will further enable improvements to the mobile platform in quality of data used by the closeout team. This will also reduce the back-end posting effort by using

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1 the native GIS data format, thereby improving data quality by reducing re-keying of
2 data. The current design software creates waste in three areas for many teams, including
3 LVD Engineering, Field Leaders, and Customer Energy Management (“CEM”) Service
4 Designers.

5 First, the current software does not support the native GIS data format, and will not
6 support future enabling work management needs. This causes waste and room for error by
7 having to re-draw designs in GIS already created, and prevents optimization of the work
8 process.

9 Second, it is not able to integrate with SAP to automatically order materials based
10 on the design.

11 Third, the current software lacks needed mobile functionality due to its lack of
12 support for the native GIS format. The designs are not geo-referenced to the exact location
13 and cannot fully use redlining capability, which causes a significant impact to data quality
14 and crew performance.

15 The project scope includes:

- 16 1. Installing a new solution that will integrate to GIS;
- 17 2. Using GIS geospatial and asset information data and the GIS platform for
18 generating Electric LVD engineering designs;
- 19 3. Integrating to and from SAP to automate Compatible and Mass Unit material
20 ordering capability;
- 21 4. Installing new and upgrading existing geospatial platform infrastructure to
22 support additional users (Electric LVD designers, Field Leaders, Planners,
23 Schedulers, etc.) of GIS;
- 24 5. Integrating to ProjectWise (engineering content management system);
- 25 6. Configuring mobile toolset;
- 26 7. Re-engineering the existing GIS data model to handle asset life cycle; and

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8. Configuration for new ArcGIS services.

Q. What benefits will this project provide?

A. This project creates value for the Company by:

1. Eliminating the need to duplicate all design work so it is in both the design system and GIS;
2. Enabling mobile editing and redlining on the design in GIS;
3. Enabling integration with SAP; and
4. Using the capabilities of the next generation GIS platform to be delivered through an in-progress business case.

Q. What alternatives did the Company consider?

A. Alternatives considered include:

1. Enhance existing software to be able to connect to GIS and SAP. This option was not selected because it is not native functionality in the current software. This would be extremely expensive to develop and implement.
2. Continue with current solution. This option was not selected as the current software and data format hinders all downstream work and asset management workflows. This adds additional effort, technologies, and costs.
3. Implement a GIS based solution. This alternative was selected because a new solution will use existing geospatial platform on premise, and will move the Company to a single data format that will enable both field and back office employees.

Q. What is the cost of this project?

A. The cost of the Electric GIS Design Platform Modernization project is \$1,476,532 in capital expenditures (\$1,181,225 Rough Order of Magnitude adjusted capital) and \$136,794 in O&M in the test year.

Q. How did the Company develop its projected expenditures for the Electric GIS Design Platform Modernization project?

A. The projected expenditures were estimated based upon previous work for this product family and anticipated software costs.

VII. ELECTRIC DISTRIBUTION O&M EXPENSES

Q. What is included in the Company's distribution O&M spending?

A. The Company's O&M spending supports its capital investments through maintenance and operation of grid infrastructure, plus engineering and design work required to execute projects, and provides for restoration of service to customers following interruptions. Forestry Line Clearing O&M is discussed by Company witness Stewart, and Service Restoration O&M is discussed by Company witness Snider.

The Company's distribution O&M spending includes: (1) funding for the Company's ongoing distribution Operations and Engineering functions; and (2) funding for certain internal organizations, such as training and equipment repair, that support both functions.

Summaries of the distribution O&M expenses are provided in Exhibits A-122 (MPK-12) and A-123 (MPK-13), and a five-year average of O&M expenses is provided as Exhibit A-124 (MPK-14).

Q. What is the overall recent trend in the Company's distribution O&M?

A. In 2024, the Company's distribution O&M was \$246,620,000, as shown in Exhibit A-124 (MPK-14), line 55, column (f). For the years 2020 through 2024, actual O&M expenses were taken from Consumers Energy's internal reporting records. The Company's projected test year distribution O&M is \$301,852,000, as shown in Exhibit A-124 (MPK-14), line 55, column (l). This test year projection is based on the sum of each individual O&M line item, which I will discuss in the subsequent sections of my direct testimony.

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1 **Q. Do test year projected O&M expenses represent continuing functions and activities?**

2 A. Yes. The Company projects that the functions and activities represented by the expenses
3 for the test year will be similar and consistent with the functions and activities that were
4 performed in 2024, with any exceptions explained below.

5 **Q. Please explain Exhibit A-128 (MPK-18).**

6 A. Exhibit A-128 (MPK-18) presents the amounts of the projected O&M expenses in my other
7 O&M exhibits, and identifies an inflation component that reflects how much inflation
8 affected O&M spending levels between the 2024 historical year and the test year in this
9 case.

10 In this exhibit, column (b) shows the historical O&M expense. Column (c) shows
11 the historical amount an inflation rate or merit increase rate was applied to. Column (g)
12 shows the amounts to which an inflation rate or merit increase rate was applied for the year
13 ending December 31, 2025. Columns (d), (f), and (h) show the merit and inflation
14 increases for each respective period. Amounts that were projected using other methods are
15 included in column (i). Column (j) is the projected test year O&M and is the sum of
16 columns (b), (d), (f), (h), and (i). Column (j) is aligned with the Company's projected
17 expenses for each sub-program for the test year, as shown in Exhibits A-125 (MPK-15)
18 and A-126 (MPK-16).

19 However, the Company's Electric Distribution O&M has generally not been
20 developed by simply taking 2024 actuals and then applying inflation rates to them. Each
21 O&M sub-program's projected expenses are developed using methodologies specific to
22 the sub-program, which I will discuss throughout this O&M section of my testimony.

1 The purpose of Exhibit A-128 (MPK-18) is simply to identify an inflation rate and
2 an inflation component so that intervenors who wish to consider alternative inflation rates
3 can make comparisons.

4 **Q. Is it possible to calculate unit costs for any O&M sub-programs?**

5 A. Not in a consistent way. Some O&M sub-programs are largely based on headcount, where
6 the expenses will be heavily based on the number of employees. Others are based largely
7 on projected work volumes. However, many O&M expenses correspond to fixed costs that
8 do not vary with any kind of unit. Many O&M sub-programs involve some kind of blend
9 of inputs, being based on some combination of headcount, work volume, and fixed or
10 one-time costs.

11 **VIII. ELECTRIC OPERATIONS**

12 **Q. Please detail the O&M programs which comprise Electric Operations.**

13 A. As shown in Exhibit A-125 (MPK-15), Electric Operations includes the following
14 programs:

- 15 • O&M Associated with Construction;
- 16 • Non-Forestry Reliability (Forestry-related Reliability is discussed in Company
17 witness Stewart's testimony);
- 18 • Operations, Maintenance, and Metering;
- 19 • Service Restoration;
- 20 • Field Operations;
- 21 • Compliance and Controls;
- 22 • Planning and Scheduling;
- 23 • Work Management and Customer Delivery;
- 24 • Operations Management; and

- Operations IT Projects.

A. O&M Associated with Construction

Q. Please describe expenses associated with the O&M Associated with Construction Program.

A. In historical years, the Company incurred O&M expenses to purchase transformers, regulators, auto boosters, and isolators for use across the electric distribution system, with these expenses offset to various degrees by credits accounted for at purchase, and subsequently allocated back to this O&M program when the equipment was installed or retired. The Company is not projecting any expenses in the O&M associated with the Construction Program in the bridge period or test year.

B. Non-Forestry Reliability

Q. Please describe the O&M expenses related to the Non-Forestry Reliability Program.

A. The Company's Non-Forestry Reliability O&M Program focuses on inspecting and monitoring system equipment. The Non-Forestry Reliability Program consists of four sub-programs:

- LVD Lines Reliability;
- HVD Lines Reliability;
- LVD Substations Reliability; and
- HVD Substations Reliability.

LVD Lines Reliability

Q. What work activities are carried out in the LVD Lines Reliability O&M sub-program?

A. The LVD Lines Reliability O&M sub-program supplements the LVD Lines Reliability capital sub-program through inspection and maintenance of LVD lines and LVD Metro

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assets. As illustrated in the Reliability Roadmap, IEEE recommends a certain cadence for inspecting different components of the LVD system, and repairing any issues that are identified. This includes general pole and line inspections, padmount inspections, and inspections of devices and equipment like reclosers, switches, and capacitors.

Q. Please describe general LVD line and pole inspections.

A. General LVD line inspections are conducted as discussed in the testimony of Company witness Partlan. Issues identified in those inspections that are not capital replacements are corrected through this O&M program; issues that do require capital replacements are generally addressed in the LVD Lines Demand Failures sub-program. Some examples of this O&M work include:

- Replacing a fuse link to put a fuse back into service or correct system protection issues, including device reach and coordination between devices;
- Moving a jumper on a line or device to balance load among phases or reconfigure the customer's service;
- Bringing assets up to existing standards, such as by moving lightning arrestors to the load side of the transformer cutout;
- Replacing damaged/stolen components, such as sections of copper down grounds that have been stolen or broken crossarm braces;
- Adding or correcting existing labels for devices in the field to match Company records; and
- Adding animal mitigation due to past animal related outages.

This also includes groundline pole inspections to identify individual LVD poles that need to be replaced. Groundline pole inspections are discussed in more detail in Company witness Partlan's testimony.

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1 **Q. What is included in padmount inspections?**

2 A. The exterior of padmounted equipment (including the base) is visually inspected each year
3 for any signs of leaking oil, holes that expose electrical components, missing transformer
4 locks, or missing labels. If found, the holes are patched, and labels are replaced. If
5 equipment is unrepairable, replacement of equipment is done under the LVD Lines
6 Demand Failures sub-program as described in the testimony of Company witness Partlan.

7 **Q. What work is done on devices and equipment?**

8 A. Maintenance of devices and equipment is required to maintain the benefits of these devices
9 and equipment. The Company can remotely monitor equipment equipped with a modem
10 to identify when it is not functioning properly. When this occurs, the device or equipment
11 is investigated to determine the cause. If the equipment or device is unrepairable,
12 replacement of equipment is done under the LVD Lines Demand Failures capital
13 sub-program.

14 Equipment without a modem needs to be inspected on a cycle to ensure it is
15 functioning properly. This equipment includes a portion of electronic reclosers, and all
16 Gang Operated disconnect switches. Electronic reclosers without a modem need the
17 control unit checked for error codes. If an error is found, the recloser is investigated to
18 determine the cause. If the recloser is unrepairable, replacement of recloser is done under
19 the LVD Lines Demand Failures capital sub-program.

20 All electronic reclosers require battery replacement to ensure the battery is working
21 correctly and the electronic controls of the recloser operate as intended. Batteries should
22 be replaced on a four-year cycle.

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1 Gang Operated disconnect switches need to be inspected for damage or erosion and
2 cycled to ensure they work properly when needed for load transfers or isolation of damage.
3 If damage or erosion is found or the switch does not cycle correctly, it can be repaired or
4 replaced, depending on the issue.

5 **Q. How does this work benefit customers?**

6 A. This work benefits customers by reducing outages caused by failed equipment, improving
7 public safety, improving power quality, getting the full life out of installed equipment, and
8 reducing electric load.

9 LVD line and pole inspections proactively identify failed equipment, providing a
10 reliability benefit to customers by improving the condition of system equipment when
11 failed components are replaced and placing the system back into a normal operating
12 condition, eliminating an outage in the future. It is estimated the average order saves
13 50,000 customer-outage-minutes.

14 Padmount inspections provide a public and environmental safety benefit. The
15 Company reduces the risk of the public coming in contact with energized equipment by
16 fixing holes and replacing locks. Identifying oil leaks ensures a minimal amount of
17 transformer oil is released to the environment and timely correction of leaks.

18 Maintenance of devices and equipment ensures the devices operate as intended and
19 are available for use when needed. It also allows the Company to get the benefits from the
20 full life of the equipment.

21 When electronic reclosers have errors, they may not operate as intended. This could
22 mean causing outages to customers when no sustained fault is present or causing the
23 upstream device to open instead, causing more customers to be impacted by an outage. On

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1 average, electronic reclosers on the LVD lines feed 670 customers, which means they have
2 a large impact on customers. Timely battery replacements ensure the electronic reclosers
3 have power and can be operated by line crews, improving restoration time.

4 Capacitor banks help to improve power quality for customers and reduce losses on
5 the electric system by improving the power factor of the electric system. They are one of
6 the components of the Company's CVR project, as discussed in Company witness Partlan's
7 direct testimony. Keeping capacitor banks operational is integral to the success of the CVR
8 program.

9 Gang Operated Switches are used to isolate damage and transfer load from a circuit
10 over to the adjacent circuit. They are regularly used in both planned and emergent events
11 where equipment or lines need to be taken out of service. They are used to keep as many
12 customers restored as possible during planned work, and to more quickly restore customers
13 during emergent events.

14 **Q. How much is the Company projecting to spend in the test year in this case?**

15 A. As shown in Exhibit A-124 (MPK-14), line 4, column (I), the Company is projecting to
16 spend \$8,000,000 in the test year.

17 **Q. How was this spending amount determined?**

18 A. This spending amount is based on the Company's costs to complete the inspection and
19 maintenance work described above. In particular, the Company is projecting to spend
20 \$3,500,000 in the test year on maintaining disconnect switches, \$2,200,000 on the
21 groundline pole inspection program, and \$500,000 on padmount inspections. The
22 remaining \$1,800,000 will be spent on the other LVD inspections defined in the Reliability
23 Roadmap.

1 **Q. What is driving the increase in spending in this sub-program compared to recent**
2 **levels?**

3 A. Historic spending levels in this sub-program were insufficient to complete all of the IEEE-
4 recommended work. The Company identified this issue when developing the Reliability
5 Roadmap in 2023, and began developing a plan to increase needed maintenance work
6 going forward. Additionally, the groundline LVD pole inspection program is essential for
7 the Company to be able to replace deteriorated LVD poles on its system.

8 **HVD Lines Reliability**

9 **Q. What work activities are carried out in the HVD Lines Reliability O&M sub-**
10 **program?**

11 A. The Company's HVD Lines Reliability O&M sub-program includes the expense portion
12 of the Company's HVD pole inspections, which occur on a 12-year cycle; and annual
13 Motor Operated Air Break Switches ("MOABS") tests. Each of these is fundamental for
14 maintaining HVD line assets. MOABS are a key component of SCADA on the HVD
15 system, and are tested annually to ensure the controls are in proper working order. Also,
16 the batteries are replaced every three to four years or sooner, as needed. The 12-year pole
17 inspection cycle is discussed in the direct testimony of Company witness Hayward. The
18 inspection data and information gathered through this O&M sub-program is key
19 information used to assist in identifying line capital projects.

20 **Q. How does this work benefit customers?**

21 A. Both pole inspections and MOABS testing identify assets (poles and switches) for repair
22 or replacement. These repairs and replacements *significantly* reduce the number of outages
23 that would occur if this work were not performed (in the case of pole replacements) or
24 greatly reduce the impact of outages when they do occur (in the case of MOABS).

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Company witness Hayward details the benefits of HVD Lines Reliability investments supported by these inspections in her direct testimony.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 5, column (l), the Company is projecting to spend \$891,000 in the test year.

Q. How was this spending amount determined?

A. This spending amount is based on the projected amount of work expected in this sub-program, specifically HVD pole inspections, testing of MOABS, and MOABS battery replacements.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending is being driven by increased inspections and testing to support projected investment increases in the HVD Lines Reliability capital program.

Substations Reliability – LVD and HVD

Q. Please describe the general work associated with both the LVD and HVD Substations Reliability sub-programs.

A. These two sub-programs provide proactive inspections and maintenance to equipment to maintain operational functionality of LVD and HVD substation assets, as well as the Company's Metro assets.

While *proactive* work is done in the LVD and HVD Substations Reliability O&M sub-programs, *reactive* work to fix assets already broken is performed by this same workforce in the LVD and HVD Substations Demand O&M sub-programs described later in my direct testimony. Though there are separate line items for LVD and HVD substations,

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1 the same Company workforce addresses both asset groups using a common plan - in short,
2 a single substation operations workforce performs work in four different O&M
3 sub-programs.

4 As discussed in the Reliability Roadmap, the Company is increasing its total
5 substation O&M spending across the four sub-programs to better align with the *Electric*
6 *Substation Reliability Guidelines* (“ESR-1”). Historical levels of funding have not been
7 adequate to complete sufficient inspections or to address maintenance backlogs.

8 Substation inspections are particularly important because they allow the Company
9 to monitor the health of transformers, load tap changers, oil circuit breakers, and other
10 critical substation equipment. If equipment is not monitored, the risk of failure increases,
11 and these kinds of substation equipment failures can result in lengthy and widespread
12 outages lasting until repairs can be made.

13 Additionally, ongoing substation maintenance provides these benefits:

- 14 • Increased reliability and resiliency by avoiding outages due to equipment
15 failure or mis-operation;
- 16 • Decreased costs by avoiding emergency repairs, allowing for more
17 predictability in the capital workplan; and
- 18 • Extension of asset life, avoiding emergent capital replacements and allowing
19 for more predictable future capital investments.

20 **Q. Please describe the work in the LVD Substations Reliability O&M sub-program as**
21 **shown in Exhibit A-125 (MPK-15), line 6.**

22 **A.** The LVD Substations Reliability O&M sub-program supports substation and substation
23 equipment inspections, recloser and circuit breaker test operating, and substation battery
24 maintenance. This O&M sub-program also supports Metro system inspections. This
25 sub-program includes required environmental inspections under the Spill Prevention,

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1 Control and Countermeasure (“SPCC”) Program. These equipment inspections are based
2 on manufacturers’ recommendations, industry best practices, and years of experience with
3 the equipment in question, and include maintenance activities such as lubrication and
4 changing of filters. Neglecting these inspections can result in premature equipment failure
5 and additional capital expense.

6 Funding for 80% of the total HVD and LVD substation mowing and weed spraying
7 expenses is included in this sub-program, and consists of typically one weed spray per year
8 (a second weed spray was performed in 2021 due to unusually vigorous weed growth
9 statewide) and a five-month (May through September) mowing program with a two-times-
10 a-month mow interval.

11 Issues identified by inspections or patrols under this program are corrected through
12 work orders in the LVD Substations Demand O&M sub-program, the LVD Substation
13 Reliability capital sub-program, or the LVD Substation Demand Failures capital
14 sub-program. Increased spending in this program will increase the number of substation
15 equipment inspections that can be performed.

16 **Q. Please describe the benefits to customers provided by the LVD Substations Reliability**
17 **sub-program.**

18 A. The LVD Substations Reliability sub-program includes inspections and maintenance that
19 help avoid LVD substation outages. Bi-monthly patrol inspections of LVD substations
20 identify issues that cannot be found through other means. In recent years, such inspections
21 identified items such as copper theft from the substation, cracked and broken insulators, a
22 burned up recloser control, and a broken pole—all of which could affect system operation
23 and potentially result in outages.

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1 On average, the total SAIDI minutes due to LVD Substation outages is
2 6.35 minutes. The average LVD substation outage resulted in 0.30 SAIDI minutes (the
3 equivalent of 3,110 customers out of service for 180 minutes). In 2024, the most significant
4 outage in duration was on the Easton substation. This single event resulted in 0.59 minutes
5 of SAIDI (3,187 customers interrupted for 346 minutes). Company witness Hayward's
6 direct testimony also provides details on a high-impact outage at the Verona substation in
7 2024.

8 Consequently, each outage avoided has a significant benefit to system reliability.
9 Deteriorated or damaged electrical equipment can be prone to dangers such as electrical
10 arcing and/or explosions, resulting in danger to customers and Company employees.

11 Maintaining equipment allows the system to be operated as intended at its most
12 efficient level, and reduces the need for capital costs to rehabilitate or replace substations
13 as well as decrease the frequency and duration of outages.

14 **Q. Please describe the projected O&M expenses related to the LVD Substations**
15 **Reliability sub-program, as shown in Exhibit A-125 (MPK-15), line 6.**

16 A. The Company is projecting LVD Substations Reliability O&M expenses of \$5,475,000 in
17 the test year.

18 **Q. Why is projected spending increasing relative to recent historical actuals for LVD**
19 **Substations Reliability O&M?**

20 A. As noted above, historical funding levels in this sub-program have not been sufficient to
21 actually complete substation inspections on the appropriate schedule as given in the ESR-1
22 guidelines, compelling the Company to defer needed work. The Company is increasing
23 the O&M spending in the substation O&M programs to get onto the nominal cycles

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provided in the ESR-1 guidelines and clear maintenance backlogs. The projected spending level in the instant case will accomplish this.

Q. Please describe the work related to the O&M expenses for the HVD Substations Reliability sub-program as shown in Exhibit A-125 (MPK-15), line 7.

A. The goal of the Company's HVD Substations Reliability O&M sub-program is to maintain the safety and reliability of HVD substations.

This program includes several activities, such as monthly substation and substation equipment inspections, breaker test operating, and substation battery maintenance. This program includes required environmental inspections due to the SPCC Program.

Additionally, funding for 20% of the total HVD and LVD substation mowing and weed spraying expenses are included in this sub-program. Issues identified by inspections or patrols under this program are corrected using orders created under the Substation Demand—HVD O&M Program, HVD Substation Reliability Program, or HVD Lines and Subs Failures Program.

Q. Please describe the O&M expenses related to the HVD Substations Reliability sub-program, as shown in Exhibit A-125 (MPK-15), line 7.

A. The Company is projecting HVD Substations Reliability O&M expenses of \$2,349,000 in the test year.

Q. Why is projected spending increasing relative to recent historical actuals for HVD Substations Reliability O&M?

A. As with LVD Substations Reliability O&M, historical funding levels in this sub-program have not been sufficient to actually complete substation inspections and maintenance on the appropriate schedule as given in the ESR-1 guidelines, compelling the Company to

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1 defer needed work. The Company is increasing the O&M spending in all four substation
2 O&M programs relative to historical averages to get onto the nominal cycles provided in
3 the ESR-1 guidelines and clear maintenance backlogs. The projected spending level in the
4 instant case will accomplish this. Note that in the case of HVD Substations Reliability
5 O&M, projected test year costs are higher than the recent average but are in line with levels
6 from 2024.

7 **Q. Please describe the benefits to customers provided by the HVD Substations Reliability**
8 **sub-program.**

9 A. The HVD Substations Reliability sub-program includes inspections and maintenance that
10 are expected to avoid HVD substation outages. On average, the total SAIDI due to HVD
11 substation outages is 2.39 minutes. The average HVD substation outage resulted in
12 0.30 SAIDI minutes (the equivalent of 3,110 customers experiencing a 180-minute outage)
13 but can be much larger in scope when they occur (such as the outage at Morrow Substation
14 in January 2019 resulting in 2.686 SAIDI minutes). Consequently, each outage avoided
15 has a significant benefit to system reliability. Additionally, there are public and Company
16 safety benefits from having periodic inspections of HVD substations as electrical
17 equipment that is deteriorated or damaged can be prone to dangers such as electrical arcing
18 and/or explosions.

19 Lastly, maintaining equipment allows the system to be operated as intended and at
20 its most efficient level, which keeps costs down and can decrease the frequency and
21 duration of outages.

1 **C. Operations, Maintenance, and Metering**

2 **Q. Please describe the work related to the Operations, Maintenance, and Metering**
3 **Program (w/out Service Restoration), as shown in Exhibit A-125 (MPK-15), line 21.**

4 A. The Company's Operations, Maintenance, and Metering O&M expenses consist of three
5 demand sub-programs and the associated Electric Equipment Repair Center located in
6 Alma. Additionally, the expense for Dissolved Gas Analysis testing of LVD and HVD
7 substation equipment is included in this sub-program.

8 The Company's LVD Operations, Meter Services, and Meter Readings O&M
9 spending includes several demand programs related to front-line operations of the
10 distribution grid.

11 **Q. What are the sub-programs contained within the Electric Operations, Maintenance,**
12 **and Metering O&M expense program?**

13 A. The sub-programs, as shown in Exhibit A-125 (MPK-15), lines 9 through 21, are:

- 14 • HVD Lines Demand;
- 15 • LVD Substations Demand;
- 16 • HVD Substations Demand;
- 17 • Corrective Maintenance;
- 18 • Staking;
- 19 • Meter Services;
- 20 • Meter Credits;
- 21 • Streetlighting;
- 22 • Service Calls;
- 23 • Alma Equipment Repair;

- Meter Reading;
- Meter Tech & Management System Support; and
- Smart Energy Meter Technology Center (“MTC”)-Electric.

HVD Lines Demand

Q. What work activities are carried out in the HVD Lines Demand O&M sub-program?

A. The Company’s HVD Lines Demand O&M sub-program includes certain expenses for repairs to 46 kV and 138 kV lines equipment. Specifically, these expenses address non-capital HVD failures identified in routine inspections or emergent customer-impacting events. For example, if a tree falls on a line and breaks it, a crew will fix the line, and this work is not capitalized. The HVD system is the backbone of the electric distribution system, and the work in this sub-program mitigates large and long outages that would otherwise come when these assets fail.

This sub-program also includes associated on-call costs for line crews. The Company has five or six crews on call at any given time to ensure they can be quickly deployed following outages. When large storm events are predicted, the Company may obtain additional or enhanced on-call crews. Activities in this program are typically emergent and identified by failures resulting in customer outages, failures resulting in equipment outages, key calls, helicopter patrols, ground patrols, and investigation of trip and reclose occurrences.

Q. How does this work benefit customers?

A. This sub-program supports preventative maintenance with repairs and upgrades of non-capital assets, downed wires, as well as splice and connector replacements. These repairs are completed to prevent outages and improve system integrity and reliability. In particular, the Company’s 46 kV system is approximately 37% radial. On radial lines,

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1 outages that require repairs before restoring customers contribute about 0.5 SAIDI minutes.
2 If the Company is able to restore power before completing the repair, SAIDI contribution
3 is about 0.1 minutes.

4 **Q. How much is the Company projecting to spend in the test year in this case?**

5 A. As shown in Exhibit A-124 (MPK-14), line 9, column (I), the Company is projecting to
6 spend \$2,979,000 in the test year.

7 **Q. How was this spending amount determined?**

8 A. This spending amount was determined based on the projected number of HVD lines work
9 orders that the Company will have to complete in the test year.

10 **Q. What is driving the increase in spending in this sub-program compared to recent**
11 **levels?**

12 A. The Company has been making increasing use of technology, particularly infrared cameras,
13 to identify anomalies on the HVD system, meaning more anomalies are being found. This
14 has created a backlog, and the Company is increasing its spending in HVD Lines Demand
15 O&M to address the backlog and continue fixing anomalies that are found.

16 **Substations Demand—LVD and HVD**

17 **Q. Please describe the general work associated with both the LVD and HVD Substations**
18 **Demand sub-programs.**

19 A. These two sub-programs respond to failures resulting in customer outages or equipment
20 outages, poor testing results (e.g., infrared inspections, oil sampling, etc.), and substation
21 asset management database algorithms, supporting the Company's safety and reliability
22 objectives by ensuring customer and electric system safety, outage restoration, and repairs
23 to equipment to maintain operational functionality of LVD and HVD substation assets.

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As noted earlier in my direct testimony, these two sub-programs employ the same Company workforce and overall workplan, along with the LVD and HVD Substations Reliability O&M sub-programs, and the Company is projecting increased spending in these sub-programs to ensure the Company can complete the necessary substation maintenance under the ESR-1 guidelines, as given in the Reliability Roadmap.

Q. Please describe the work related to the LVD Substations Demand sub-program.

A. The Company's LVD Substations Demand O&M sub-program includes expenses for emergent restoration and corrective maintenance on LVD substation equipment and facilities. This program includes work on the equipment, facilities, infrastructure, and property associated with LVD substations.

In addition, the Company is required to correct situations where equipment in substations violates National Electric Safety Code ("NESC") requirements for working space clearance (typically between live components in control panels and other panels, walls, etc.). The Company has committed to complete all this work by 2028 under a 10-year plan.

Q. Please describe the O&M expenses related to the LVD Substations Demand sub-program as shown in Exhibit A-125 (MPK-15), line 10.

A. The Company is projecting LVD Substations Demand O&M expenses of \$6,398,000 in the projected test year, as set forth in Exhibit A-125 (MPK-15), line 10, column (f).

Q. Why is LVD Substations Demand O&M spending increasing relative to historical levels?

A. As with the two Substations Reliability O&M sub-programs, historical funding levels in this sub-program have not been sufficient to complete substation inspections on the

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1 appropriate schedule as given in the ESR-1 guidelines, compelling the Company to defer
2 needed work. The Company is increasing the O&M spending in all four substation O&M
3 programs to get onto the nominal cycles provided in the ESR-1 guidelines and clear
4 maintenance backlogs. The projected spending level in the instant case will accomplish
5 this. More inspections in the two Substations Reliability O&M sub-programs will result
6 in more issues to address in the two Substations Demand O&M sub-programs.
7 Historically, every \$1 spent in a Reliability O&M sub-program on inspections has yielded
8 \$1.70 in maintenance needs in the corresponding Demand O&M sub-program.

9 **Q. Please describe the work related to the HVD Substations Demand sub-program.**

10 A. The Company's HVD Substations Demand O&M sub-program includes expenses for
11 unplanned and emergent restoration, as well as corrective maintenance on HVD and
12 Strategic Customer substation equipment and facilities. In addition, the Company is
13 required to correct several situations where equipment in substations violates NESC
14 requirements for working space clearance (typically between live components in control
15 panels and other panels, walls, etc.). The Company has committed to complete all this
16 work by 2028 under a 10-year plan.

17 **Q. Please describe the O&M expenses related to the HVD Substations Demand**
18 **sub-program, as shown in Exhibit A-125 (MPK-15), line 11.**

19 A. The Company is projecting HVD Substations Demand O&M expenses of \$5,311,000 in
20 the projected test year, as set forth in Exhibit A-125 (MPK-15), line 11, column (f).

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1 **Q. Why is HVD Substations Demand O&M spending increasing relative to historical**
2 **levels?**

3 A. As with the other substations O&M sub-programs, historical funding levels in this
4 sub-program have not been sufficient to actually complete substation inspections on the
5 appropriate schedule as given in the ESR-1 guidelines, compelling the Company to defer
6 needed work. The Company is increasing the O&M spending in all four substation O&M
7 programs to get onto the nominal cycles provided in the ESR-1 guidelines and clear
8 maintenance backlogs, which as of April 2025 was approximately 2,500 substation demand
9 orders. The projected spending level in the instant case will accomplish this.

10 **Q. Please describe the benefits to customers provided by the LVD and HVD Substations**
11 **Demand sub-programs.**

12 A. Work identified through substation inspections reduces the potential for outages from
13 unplanned events. These corrections are relatively quick and simple (e.g., lubricating
14 bearings, realigning a switch, or adding SF6 to a gas circuit breaker) and can be achieved
15 through spending in this program. Occasionally, the issues require equipment replacement
16 that would be covered under one of the capital programs (such as HVD Lines and
17 Substations Rehabilitation or HVD Lines and Subs Failures) and in some cases, such as a
18 circuit breaker repair, an evaluation must be performed to determine if a procedure such as
19 rebuilding the breaker is more cost effective than replacing the unit. Either way, it is almost
20 always more cost efficient to perform the work in a planned manner than waiting for the
21 unit to fail. This provides value to the customer and provides the best reliability. The
22 projected spending increases will allow the Company to perform additional inspections and
23 corrective maintenance.

Corrective Maintenance

Q. What work activities are carried out in the Corrective Maintenance O&M sub-program?

A. The Corrective Maintenance sub-program supports customer- and field-generated orders associated with imminent safety issues or system deficiencies, including emergent and short-term planned maintenance requirements. This most prominently consists of splicing wire on primary and secondary LVD lines, such as wires struck by trees during storms. This also consists of responding to underground faults, which takes longer than responding to those on the overhead system.

This sub-program ensures compliance with regulatory requirements, and supports the Company's safety and reliability objectives through maintenance to address safety issues and system deficiencies—this is most relevant regarding wire-down response, since this sub-program is used to splice wires damaged during storms.

Q. How does this work benefit customers?

A. The Corrective Maintenance sub-program improves public safety and reliability of the system by responding to customer reported concerns, and to damage from storms and other incidents, most critically by responding to the safety issues posed by broken wires.

While in some circumstances the Company will replace equipment and infrastructure to upgrade and improve the system, there are times when replacement is not the most cost-effective option. In these instances, a minor repair or modification that improves safety or reliability of the system can be made. For example, if a pole has minor damage, then the Company may make a minor repair to quickly restore a customer, and then not need to fully replace the pole until a later time.

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1 **Q. How much is the Company projecting to spend in the test year in this case?**

2 A. As shown in Exhibit A-124 (MPK-14), line 12, column (l), the Company is projecting to
3 spend \$5,236,000 in the test year.

4 **Q. How were these spending amounts determined?**

5 A. These spending amounts were determined by accounting for the expected level of work
6 orders. This sub-program consists largely of labor costs, and is based on projected
7 workplan hours to complete the work orders.

8 **Q. What is driving the increase in spending in this sub-program compared to recent
9 levels?**

10 A. The increase in spending is being driven by an increase in labor costs. Each year, the
11 Company's electric service workers receive a cost-of-living adjustment and union-
12 negotiated merit increases in pay. Consequently, the average standard labor rate across the
13 past five years is 16% lower than the average standard labor rate in the test year.

14 **Staking**

15 **Q. Please describe the O&M expenses related to the Staking & Locating sub-program.**

16 A. The Staking & Locating sub-program involves Company labor and contractor services for
17 the staking and locating of the Company's electric distribution facilities, in accordance
18 with the MISS DIG law (Public Act 174 of 2013 ("Act 174")), a key component of securing
19 public and employee safety. Work is typically performed by a contracted outside service
20 vendor on a multi-year contract with the Company.

21 **Q. Please discuss the work activities in the Staking and Locating Sub-Program.**

22 A. The Staking and Locating sub-program includes the following work activity categories:

- 23 • **Outside Services - Dedicated:** Contractor costs are included in the test year
24 projection for staking and locating activities performed under the Dedicated
25 Staking programs, under which contractors work solely for the Company.

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- **Company Labor:** Volumes and hours are included in the test year projection for Company labor to support abnormal operating condition efforts.
- **Licenses, Permits & Fees:** Includes fees that Consumers Energy pays to the state MISS DIG 811 system as part of Act 174.
- **System:** Use of Irth Solutions UtiliSphere to enable ticket management and reporting for contracted staking and locating, MISS DIG ticket risk scoring to enable more effective and efficient excavator intervention, and work plan management and reporting.

Q. Has the Company made any changes to the above work activity categories since its last electric rate case?

A. Historically, the Company also had “Outside Services” contractor costs for staking and locating activities under a shared resource model, in which contractors would also work for other parties besides the Company. In 2023 and 2024, the Company started using dedicated contractors who only work for the Company. Based on realized performance improvements, the Company began transitioning to a fully dedicated staking contractor model in December 2024, and completed the transition in March 2025. Therefore, in the test year in the instant case, there are no costs for Outside Services for shared contractors.

Q. Why did the Company initially pursue a dedicated contractor staking strategy?

A. The Company originally pursued this in a limited portion of the Company’s gas service territory because changes in the program were necessary to improve timeliness and accuracy of staking for public safety, especially given the continued ticket volume. When accuracy and timeliness of staking are off target, this creates negative behaviors with third-party excavators, resulting in unsafe digging practices. A critical step in ensuring safe digging practices is having excellence in stake-and-locate timeliness and accuracy. With a dedicated contractor staking strategy, the Company sought to achieve the following objectives in support of safe digging:

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- The first key objective is *timeliness*. Through the dedicated workforce, the Company will see improved timeliness compared to historical performance to support the excavating community. This will be achieved by having a single utility focus for ticket management. This model improves the ability to manage ticket volume fluctuations throughout the year due to not having the risk of completing all other commitments on the ticket in the shared resource model.
- Another key objective is *quality*, with improved staking accuracy performance compared to recent historical data. This is expected to be achieved as stakers need only focus on one utility type, compared to the shared resource model, where stakers are responsible for all assets (electric, gas, communications, and 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.

Please note this transition to dedicated contractor staking has also been implemented in the Company's gas business, and is also discussed in detail by Company witness James P. Pnacek in the Company's most recent Gas Rate Case in Case No. U-21806.

Q. Why is the Company expanding its dedicated contractor staking to its entire service territory?

A. Based on initial benefit realizations, the Company planned to expand its Dedicated Contractor Staking Program to expand the benefits. The staking contract with the contractor that the Company used for its shared contractor approach was set to expire in the first quarter of 2025. In anticipation, the Company sent out a request for proposal in the third quarter of 2024 for staking services for the Company's remaining service territory that at the time was under the shared contractor resource model. The request included options for both shared and dedicated services. The bids yielded an average unit cost for the dedicated contractor resource model that was below the average unit cost of the shared

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contractor staking model, by an average of \$0.51 on a per unit basis. Based on the lower unit cost, the realized timeliness, and quality improvement from the dedicated contractor resource model, the Company elected to pursue the lower cost, dedicated contractor option and implement a statewide dedicated contractor staking approach for its entire service territory.

Q. What actual benefits from dedicated contractor staking did the Company realize in 2023 and 2024?

A. In 2023, with the initial implementation of the dedicated contractor resource model in place in two-thirds of Oakland County (compared to the shared contractor resources model used in 2022), the Company saw the following results:

- Gas accuracy related to at fault damage reduction improved by 87.3%.
- Field timeliness for the dedicated contractor model averaged 98.7% compared to 97.3% for the shared contractor resource model in 2023.

For 2024, with the dedicated contractor model expanded to cover Oakland County and Kent County, the Company saw the following results compared to the former shared contractor resources model:

- Gas distribution accuracy related to at fault damage reduction improved by 78% from 2022.
- Electric distribution accuracy related to at fault damage reduction improved by 80% from 2023.
- Field timeliness for the dedicated contractor model averaged 99.7% (including 24 hour re-transmits) compared to 95.1% for the shared contractor resource model in 2024.

Q. What benefits does the Company anticipate going forward?

A. The Company anticipates fully pursuing a dedicated contractor model will improve timeliness by 4-5%, allowing the Company to regularly achieve 98% or greater timeliness. The Company also expects that it will see a 50-75% reduction in damages caused by

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third-party locating. Additionally, the Company believes dedicated contractors will lead to improved communication and partnership with the contractors.

Q. Please provide a breakdown of Staking and Locating sub-program expenses.

A. The Staking & Locating sub-program expenses for 2024 and the test year in this case are identified in Figure 49 below:

FIGURE 49
STAKING AND LOCATING SUB-PROGRAM PROJECTION BREAKDOWN BY ACTIVITY TYPE

Work Type	2024 Actual	Test Year
Outside Services – Staking and Locating	\$3,356,806	\$0
Outside Services – Dedicated electric staking and locating	\$2,406,613	\$13,249,346
Company labor	\$0	\$9,534
Licenses, Permits & MISS DIG Fees	\$384,642	\$689,338
Total Program	\$6,148,061	\$13,948,218

Q. What is the basis for determining the \$13,948,218 of projected O&M expenses in the test year for this sub-program?

A. Spending in this sub-program is primarily driven by staking request volume (units). The primary drivers for increased spending in the test year in this case include:

- (a) increase in the cost per ticket under the contracts with staking contractors (\$6,760,338 total increase) includes dedicated model expansion;
- (b) anticipated contractor volume increases (\$725,589 total increase);
- (c) Company labor and volume increase (\$9,534 total increase); and
- (d) increases in MISS DIG 811 membership fees (\$304,696 total increase).

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1 **Q. Describe the test year forecast for volume and unit costs.**

2 A. An anticipated unit cost increase is included in the test year projection for contractor
3 services, in alignment with historical data and the requirement for enhanced capability to
4 manage increased demand in performance and increasing labor costs.

5 The staking completed by an outside contracted vendor is billed based on
6 contractual unit costs.

7 An anticipated volume increase of 7% is included in the test year projection relative
8 to 2024 contractor services. This is in alignment with the historical data and staking
9 forecasts for the state of Michigan. The anticipated contractor unit cost and staking volume
10 increases are shown in the following table:

FIGURE 50
Historical Data and Unit Cost Staking Forecasts

Contractor Stake & Locate Services		
	Base Unit Forecast (units)	Base Unit cost (\$/unit)
2024 Actual	433,137	\$13.32
2025 Projected	446,893	\$26.06
2026 Projected	478,176	\$26.93
2027 Projected	511,648	\$27.81

11 The Statewide MISS DIG 811 Annual Ticket Requests table below shows the
12 change in staking volumes realized year over year.

13 MISS DIG 811 data²⁰ shows a continuous growth in staking and locating ticket
14 requests for the entire state of Michigan, except for a small decline in 2020, which appears
15 to be a temporary result of COVID-19 pandemic business impacts. Given a projected

²⁰ <https://www.missdig811.org/about/who-we-are/about-miss-dig.html>

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increase in staking volumes tied to expansion of rural broadband internet infrastructure, growth is expected to further increase, going forward, to 7% per year.

The following is the historic and projected Statewide MISS DIG 811 annual ticket requests:

FIGURE 51
MISS DIG ANNUAL GROWTH

MISS DIG 811 Statewide Annual Growth ²¹			
Years	Annual Ticket Requests	Prior Year Requests	% Change
2017	872,896	814,303	7.2%
2018	923,993	872,896	5.8%
2019	1,015,753	923,993	9.9%
2020	994,573	1,015,753	-2.1%
2021	1,088,030	994,573	9.4%
2022	1,093,021 *	1,088,030	0.5%
2023	1,202,992	1,093,021 *	10.1%
2024	1,327,894	1,202,992	10%
2025 Forecast	1,420,847	1,327,894	7% (assumed)
2026 Forecast	1,520,306	1,420,847	7% (assumed)
2027 Forecast	1,626,727	1,520,306	7% (assumed)

*Volume impacted by MISS DIG 811 Pelican implementation

Q. Please describe the Company's concerns with the increase in staking ticket volumes and proposed recommendation.

A. The Company has estimated staking tickets for the test year based on the best information available at this time. With staking requests increasing due to fiber optics and other infrastructure work, the actual staking demand the Company experiences in 2026 could be

²¹ MISS DIG 811 Data Reference - <https://www.missdig811.org/about/who-we-are/about-miss-dig.html>

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1 above the Company's staking volume forecast. While the Company attempts to forecast
2 staking volumes with a high degree of accuracy, the largest factors influencing
3 expenditures in these programs are externally driven. As a result, the Company requests it
4 be allowed to defer for refund or recovery of any O&M expenses for this program, below
5 or above amounts included in rates for the test year; this treatment was also requested by
6 the Company in the Company's most recent Gas Rate Case in Case No. U-21806. This
7 request would avoid potential constraints on other important programs if higher than
8 anticipated staking costs outside the Company's control are incurred. It would also prevent
9 customers from paying for costs that were not incurred if staking volumes are below
10 forecasted levels.

11 The Company is basing its deferral request mainly on two high-speed internet
12 infrastructure grant programs administered by the Michigan High-Speed Internet Office
13 ("MIHI") located within the Prosperity Division of the Department of Labor and Economic
14 Opportunity. The first program is Realizing Opportunities with Broadband Infrastructure
15 Networks ("ROBIN"). The second program is the Broadband Equity, Access, and
16 Deployment Program ("BEAD").

17 **Q. Please describe the test year costs related to dedicated locating.**

18 A. In the interest of public safety, damage prevention, and in compliance with a facility
19 owner's obligation under Act 174, the act of placing marks to indicate approximate facility
20 location in response to a MISS DIG ticket requested in advance of excavation activity, an
21 anticipated increase in volume and costs are included in the test year projection for
22 dedicated locating. This includes resources to locate *only* for Consumers Energy facilities,
23 contrasted to the existing method of vendors locating several other additional external

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1 facilities. This focus substantially mitigates public safety, damage, timeliness, quality, and
2 communication risks with excavators in some of the highest areas for staking requests for
3 Consumers Energy, encompassing 100% of requests starting in April of 2025.

4 **Q. Please describe the Company's plan to expand the Dedicated Contractor Staking**
5 **Program.**

6 A. Based on existing benefit realization for the Dedicated Contractor Staking Program, the
7 Company plans to expand the program to continue to improve public safety, reduce
8 damages, mitigate communication risks with excavators, improve quality, and comply with
9 the timeliness requirement within Act 174.

10 In 2024, Kent and Oakland counties were managed under the Dedicated Staking
11 model accounting for 17% of the total staking ticket volumes. In 2025, the Company plans
12 to expand the Dedicated Contractor Staking Program to include the Company's entire
13 statewide electric service territory and cover up to 100% of the total staking ticket volume.
14 The dedicated model will already be fully implemented during the test year.

15 **Q. Why did the Company choose to start the Dedicated Contractor Staking Program**
16 **instead of hiring more contract stakers to improve staking quality?**

17 A. Hiring additional contractors would follow the shared resource model, which shares
18 staking resources with other companies and assets.

19 The shared resource model carries risks, including skilling proficiencies related to
20 delivering timeliness and quality performance as it relates to staking existing infrastructure.
21 The Dedicated Contractor Staking Program uses a dedicated resource for Company assets
22 *only*, so stakers can become efficient and proficient on Company asset staking without
23 having to focus on other facilities such as communications, water, etc.

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1 The dedicated workforce model substantially mitigates many of the risks associated
2 with the shared resources model as described earlier in this section.

3 **Q. Please explain the MISS DIG cost increase.**

4 A. MISS DIG 811 costs were assessed in 2023 by the MISS DIG Board, and adjusted as of
5 January 2024 based on actual utilization for members, which resulted in an increase for the
6 Company.

7 **Meter Services and Credits**

8 **Q. What work activities are carried out in the Meter Services and Credits O&M**
9 **sub-program?**

10 A. This O&M sub-program funds Electric Meter Operations (“EMO”), whose expenses are
11 partially offset by first-set and retirement credits of both electric meters and metering
12 transformers.

13 When the Company buys meters, it capitalizes them the first time they are installed
14 (including labor) in the Metering capital program; the first-set credit offsets O&M and
15 reduces O&M by the amount being capitalized. When a meter is retired, a retirement O&M
16 credit is issued against cost of removal.

17 EMO responds to customer-initiated and Company-generated orders for
18 installation, replacement or repair, and inspection of new and existing metering
19 installations to ensure customers have a safe, reliable, and accurate metering installation.
20 This sub-program also installs, removes, and maintains demand response and power quality
21 installations.

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1 **Q. Please explain the Credit portion of this O&M program.**

2 A. Meters and metering transformers are purchased through the LVD Metering capital
3 sub-program, discussed by Company witness Partlan in her direct testimony. In addition
4 to the direct cost for electric meters and metering transformers, a first-set credit value is
5 included to offset the cost of labor for installation. When electric meters and metering
6 transformers are purchased and received, the first-set credit value for each meter is totaled
7 at the end of each month and credited back to O&M for the installation labor. When electric
8 meters and metering transformers are retired, the cost of removal credit is totaled at the end
9 of each month and credited back to O&M for the final removal labor. The credits are
10 intended to partially offset the labor costs associated with new and retired metering
11 installations.

12 **Q. How does this work benefit customers?**

13 A. This work benefits customers by ensuring that all customers, from residential to
14 commercial and industrial ("C&I") and generation and transmission interconnections, have
15 reliable and accurate billing information. Additionally, smart meters are required for
16 customers to participate in programs like time of use rates, to see their usage in the
17 customer portal, etc.

18 Metering also impacts reliability. Metering infrastructure is aging, with some
19 metering transformers more than 60 years old. The Company continues to inspect and
20 maintain these transformers, but eventually more intentional replacements of wiring and
21 other components are needed to prevent meter failures that would cause outage minutes.

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1 **Q. How much is the Company projecting to spend in the test year in this case?**

2 A. As shown in Exhibit A-124 (MPK-14), line 14, column (l), the Company is projecting to
3 spend \$17,088,000 in the test year on meter services. As shown in Exhibit A-124
4 (MPK-14), line 15, column (l), the Company is projecting \$10,257,000 in meter credits in
5 the test year. This results in a net expense of \$6,831,000 for the test year.

6 **Q. How were these spending amounts determined?**

7 A. These spending amounts were determined by considering projected workload. The
8 Company projects a volume of work based on historical data and expected growth from
9 areas like New Business. Workload projections assume a certain number of hours to do
10 given work, based on historical productivity, which is translated into expenses for meter
11 installations. Total credits are based on projections for new meter capital purchases, and
12 projections for retirements. The credit rate calculation is determined monthly, which is
13 calculated considering labor, vehicle loadings, and non-premise cost. These amounts are
14 then apportioned by an electric mix factor (a portion of the meters are installed by EMO
15 and others by Distribution) and then multiplied by the average time required to either install
16 (for first set credits) or remove (for retirement credits) a meter. This calculation varies
17 based on meter or transformer type.

18 As an example, for November 2024, for a single-phase, 200 Amp, smart meter, the
19 calculated 1st set credit was as follows:

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Figure 52
Example of Credit Rate Calculation

	Distribution	EMO
Standard Labor Rate	\$ 98.51	\$ 73.64
+		
Standard Labor Rate * Vehicle Loading		
Standard Labor Rate	\$ 98.51	\$ 73.64
Vehicle Loading	0.01	0.15
	\$ 0.99	\$ 11.05
+		
Standard Labor Rate * Non-Premise		
Standard Labor Rate	\$ 98.51	\$ 73.64
Non-Premise	0.43	1.6
	\$ 42.36	\$ 117.82
=		
Loaded Hourly Rate	\$ 141.85	\$ 202.51
*		
Electric Meter Mix	0.22	0.78
=	\$ 31.21	\$ 157.96
Blended Loaded Hourly Rate	\$	189.17
*		
Average Install Time (hr)	0.23	
=		
1st Set Credit Rate	\$	43.51

The retirement credit rate is calculated using the same methodology, with the exception that instead of the average install time, the average remove time is used, in this case, 0.13 hr, resulting in a retirement credit rate of \$25.22 per unit.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The level of credits in this sub-program remains relatively flat for the next several years, partially due to inventory carried over from previous years of meters. However, because of this carried over inventory, the Company is not making as many capital purchases of meters. This means that EMO work is spread over fewer capital purchases, which makes Meter Services expenses higher.

Streetlighting

Q. What work activities are carried out in the Streetlighting O&M sub-program?

A. Streetlighting O&M supports the personnel and materials necessary to complete streetlight maintenance activities. Examples of Streetlighting O&M expenses include: underground fault investigations, minor repairs including conductor splicing and replacement of photo cells, and shield installation on light-emitting diode luminaires.

Q. How does this work benefit customers?

A. Streetlights provide illumination to enhance safety and the aesthetics of roadways, residential areas, and cityscapes in various applications throughout the Company's service territory. This work complements the capital investment in company owned streetlights.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 16, column (l), the Company is projecting to spend \$2,089,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined based on historical O&M expenses, and an increased focus on long-duration outage investigation and repair.

Q. What is driving the increase in spending in this sub-program compared to recent levels?

A. The increase in spending is being driven by increased time spent investigating, locating, and repairing underground-fed lights. Activities associated with failure investigation, locating, and repair of underground-supplied lights include: additional hydro excavation, on-site trouble shooting, and splicing.

Service Calls

Q. What work activities are carried out in the Service Calls O&M sub-program?

A. In the Service Calls sub-program, the Company responds to various types of requests from customers, including disconnections and reconnections, undergrounding service lines, upgrading service lines to higher capacity, and installing temporary service lines to support house construction. Customers pay for some requested work, but not for disconnections and reconnections, and the Company incurs O&M costs not billable to the customer for all types of Service Call work. The Company estimates, based on historical numbers, that employees will respond to approximately 33,000 discrete service calls annually. This O&M sub-program funds these responses.

Q. How does this work benefit customers?

A. This work benefits customers by responding to their expressed specific needs for electric service.

Q. How much is the Company projecting to spend in the test year in this case?

A. As shown in Exhibit A-124 (MPK-14), line 17, column (l), the Company is projecting to spend \$5,699,000 in the test year.

Q. How were these spending amounts determined?

A. These spending amounts were determined primarily by considering historical work order volumes. The estimated number of service calls in the Company's workplan is based on the previous year's completed work. The number of completed work orders for each month in the previous year is totaled and used as an estimate of forecasted work per month for the future year. Projected costs are directly based on the number of projected work orders.

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1 The Company translates the projected work orders into projected workplan hours to
2 complete the work, and multiplies this by labor costs.

3 In addition to projected workplan hours, the Company also adds in non-labor
4 spending, which are simply projected to remain at historical levels.

5 **Q. What is driving the increase in spending in this sub-program compared to recent**
6 **levels?**

7 A. The increase in spending in the test year is being driven by an increase in labor. Each year,
8 the Company's electric service workers receive a cost-of-living adjustment and union-
9 negotiated merit increases in pay. Consequently, the average standard labor rate across the
10 past five years is 16% lower than the average standard labor rate in the test year. In addition
11 to the labor rate increase, the Company is projecting a 17% increase in hours work during
12 the test year, compared to the historical five-year level.

13 **Alma Equipment Repair**

14 **Q. What work activities are carried out in the Alma Equipment Repair O&M**
15 **sub-program?**

16 A. The Company's Alma Equipment Repair O&M sub-program, based at the Company's
17 Alma Service Center, includes maintenance activities (testing, repairing, reconditioning)
18 for assets such as mobile substation equipment, substation oil processing equipment, and
19 substation power transformer cooling equipment. End-of-life retirement of failed and aged
20 electrical equipment such as regulators, reclosers, and pole top transformers is also handled
21 through this program. The sub-program also includes activities such as substation
22 equipment acceptance testing and ensuring compliance with all environmental regulations

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1 regarding the handling, storage, and disposal of equipment containing polychlorinated
2 biphenyl ("PCBs").

3 **Q. How does this work benefit customers?**

4 A. These activities are considered base level maintenance for system reliability and
5 emergency response to demand outages. In particular, mobile substations need to be
6 properly maintained so they are in good working order and can be deployed for field use
7 when needed. The Alma Equipment Repair O&M sub-program can also identify savings
8 for customers. For example, quickly repairing equipment like regulators, when possible,
9 represents savings when compared to capital replacements; when the Company identifies
10 damaged materials, Alma Equipment Repair employees assess if it can be fixed and
11 returned to service or if it must be scrapped and replaced, based on relative costs.

12 Additionally, the Alma Equipment Repair O&M sub-program supports safety by
13 ensuring safe disposal of hazardous substances, and offsets some costs by selling used
14 transformer oil to parties who can use or recycle it.

15 **Q. How much is the Company projecting to spend in the test year in this case?**

16 A. As shown in Exhibit A-124 (MPK-14), line 18, column (I), the Company is projecting to
17 spend \$571,000 in the test year.

18 **Q. How were these spending amounts determined?**

19 A. These spending amounts were determined based on anticipated headcount levels and the
20 volume of work expected to be done. Both headcount and workload have been relatively
21 consistent in this sub-program in recent years, and projected test year spending is closely
22 in line with recent actuals. Test year spending is slightly higher than the five-year average

1 to account for increased maintenance volume, with more mobile substations having been
2 purchased by the Company.

3 **Meter Reading**

4 **Q. What work activities are carried out in the Meter Reading O&M sub-program?**

5 A. The Meter Reading O&M sub-program includes Company employee labor, business
6 expenses (e.g., fleet and training costs), and technology expenses (e.g., hardware and
7 software maintenance, cellular, and system improvements) for purposes of obtaining meter
8 indexes for the calculation of customer bills.

9 The Company has a single Meter Reading workforce for both electric and gas
10 meters, in large part due to the ongoing need to manually read a small amount of meters
11 each month (approximately 16,000 electric meters and 16,000 gas meters in the
12 Company's service territory). This workforce also performs inspection of padmounted
13 transformers/enclosures, a strategy for keeping overall costs down; because the
14 manual-read meters are spread out geographically, the Meter Reading workforce performs
15 these inspections while enroute to meter locations. The Company also meets regulatory
16 requirements by maintaining sufficient meter reading resources.

17 Because the Meter Reading O&M sub-program is managed jointly for the
18 Company's electric and natural gas operations, the total meter reading costs are allocated
19 between electric and natural gas.

20 **Q. How does this work benefit customers?**

21 A. This work benefits customers by ensuring all customers have accurate meter reads.

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1 **Q. How much is the Company projecting to spend in the test year in this case?**

2 A. As shown in Exhibit A-124 (MPK-14), line 19, column (l), the Company is projecting to
3 spend \$1,971,000 in the test year.

4 **Q. How were these spending amounts determined?**

5 A. These spending amounts were determined by considering the projected volume of work for
6 the meter reading group and then allocating between the electric and gas businesses.
7 Allocations are typically split 60/40 in favor of gas.

8 **Meter Technology and Management System Support**

9 **Q. What work activities are carried out in the Meter Technology and Management**
10 **System Support O&M sub-program?**

11 A. The Meter Technology and Management System Support O&M sub-program funds the
12 MTC activities to support the Metering capital sub-program. Activities performed by the
13 MTC include:

- 14 • Electric meter and metering transformer testing for accuracy and function in
15 accordance with MPSC rules governing meter accuracy and testing
16 requirements;
- 17 • Evaluation of new metering and meter communications technology;
- 18 • Lifecycle assessment testing;
- 19 • Device management, including metering equipment purchase planning and
20 meter work order troubleshooting and support;
- 21 • Order fulfillment for field operations for metering equipment;
- 22 • Daily interrogations of the Company's AMI electric meters; and
- 23 • Maintenance of hardware and software firmware in the AMI electric meter
24 population.
- 25
- 26
- 27
- 28
- 29
- 30

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1 This sub-program has also taken over funding of the Smart Energy Operations Center
2 (“SEOC”) from the Field Operations O&M program, which is outlined later in my direct
3 testimony.

4 **Q. How does this work benefit customers?**

5 A. This work benefits customers by ensuring all customers, from residential to C&I and
6 generation and transmission interconnections, have reliable and accurate billing
7 information. This operation maintains the health of the electric smart meters, and enables
8 customers to participate in programs, such as the time-of-use program, and the ability to
9 have more granular information about their energy consumption through a Web portal.
10 The testing performed at the MTC keeps the Company in compliance with MPSC metering
11 rule requirements, as the annual meter routine sampling program is performed at the MTC.
12 Additionally, the sub-program funds technical assessment of new metering and
13 communications equipment related to meters, and assessment of new devices that can
14 benefit customers through programs such as load monitoring or load control devices.

15 **Q. How much is the Company projecting to spend in the test year in this case?**

16 A. As shown in Exhibit A-124 (MPK-14), line 20, column (I), the Company is projecting to
17 spend \$1,393,000 in the test year.

18 **Q. How were these spending amounts determined?**

19 A. The level of spending for this program is made up of three components: Salaried labor,
20 Union labor, and business expenses. The spending for each year is based on the current
21 headcount, including any approved vacancies with the applicable labor costs for each,
22 including inflation and expected labor increases. In addition, the projected spending for
23 this program considers any planned promotions and known business expenses that are

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1 planned for the subsequent years. Spending in this program has remained relatively flat
2 for most of the last five years.

Smart Energy MTC

4 **Q. What work activities are carried out in the Smart Energy MTC O&M sub-program?**

5 A. The Smart Energy MTC sub-program consists of four components:

6 1. Communications backhaul for both Smart Meters and Cellular-Under-Glass
7 legacy meters. Specifically, the Company's electric smart meters all provide
8 billing determinants and metering events through cellular communications, and
9 the Company pays cellular charges per meter monthly.

10 2. Meter software maintenance charges.

11 3. Technical support service charges from the Company's smart meter supplier.

12 **Q. How does this work benefit customers?**

13 A. This work benefits customers by ensuring all customers, from residential to C&I and
14 generation and transmission interconnections, have reliable and accurate billing
15 information. This operation maintains the health of the electric smart meters, and enables
16 customers to participate in programs, such as the time-of-use program, and the ability to
17 have more granular information about their energy consumption through a Web portal and
18 to realize the benefits of smart meter technology.

19 **Q. How much is the Company projecting to spend in the test year in this case?**

20 A. As shown in Exhibit A-124 (MPK-14), line 21, column (l), the Company is projecting to
21 spend \$9,226,000 in the test year.

22 **Q. How were these spending amounts determined?**

23 A. The charges underlying these spending amounts are fixed by a contract that establishes the
24 charging rates through 2032. These rates are based on the number of active electric smart
25 meters the Company has installed at customer locations, and meter inventory levels

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1 required to meet new business and meter failure requirements throughout the year. As these
2 charges are fixed, the spending forecast is based on the projected number of meters, and is
3 adjusted annually based on projections for new business, regulatory requirements, or other
4 large projects. Spending in this program has remained relatively flat for the last five years,
5 and that trend should continue in coming years.

6 **D. Service Restoration**

7 **Q. Please describe the O&M work and expenses related to the Service Restoration**
8 **sub-program.**

9 A. Company witness Snider discusses the entirety of this sub-program in his direct testimony.
10 Service Restoration O&M expenses are projected to be \$214,344,000 in the bridge period
11 and \$165,215,000 in test year. O&M dollars in this sub-program support activities
12 described within Company witness Snider's direct testimony.

13 **E. Field Operations**

14 **Q. Please describe the O&M work related to the Field Operations Program.**

15 A. The Field Operations Program consists of the cost of training, supervision, facilities, and
16 facilities maintenance for the Company's in-field operations teams.

17 These costs are planned annually based on the expected costs to maintain an in-field
18 operations team to carry out the various activities required for supporting the safe, reliable,
19 and efficient operations of the electric distribution system. This program includes labor
20 expenses for supervision and leadership for electric LVD and HVD operations. Expenses
21 include the cost of training, supervision, facilities, and facilities maintenance for in-field
22 operations teams.

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1 **Q. What are the sub-programs in the Field Operations O&M Expense Program?**

2 A. These sub-programs, as shown in Exhibit A-125 (MPK-15), lines 25 through 33, are:

- 3 1. Training;
- 4 2. Tools;
- 5 3. Field Operations Expenses;
- 6 4. Indirect Labor/Labor Variation;
- 7 5. Supervision/Admin Staff;
- 8 6. SEOC;
- 9 7. Grid Management—Distribution;
- 10 8. HVD Lines Construction Workforce; and
- 11 9. Underground Workforce.

12 However, there is no projected test year spending for the Indirect Labor/Labor
13 Variations or the SEOC sub-programs (as noted above, the SEOC is now funded through
14 the Meter Tech and Management System Support sub-program). There is also no projected
15 test year spending for HVD Lines Construction Workforce.

16 **Training**

17 **Q. What work activities are carried out in the Training O&M sub-program?**

18 A. The Training sub-program covers expenses whenever groups in the Electric Operations
19 organization conduct official training courses, generally at the Company's Marshall
20 Training Center or another designated training location, typically with a course instructor.
21 These training courses include skills-based training using both classroom time and
22 instructor-led fieldwork at the training location for Electric Operations employees,
23 including Electric Lines, Substation Operators and Maintenance, Electric Field Lab, and
24 Electric Meter Operations. For example, a training course for lineworkers to move from

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1 the Step 1 to the Step 2 classification involves about three weeks of training at the Marshall
2 Training Center. The Company also uses on-the-job training in the field for many
3 purposes, and that is not part of the Training O&M sub-program; those costs are instead
4 charged to the actual job in the field being completed.

5 The Training O&M sub-program also includes expenses for operating the
6 Company's Apprenticeship Program, including paychecks earned by apprentices while
7 they are at the training center. Aside from the Apprenticeship Program, union labor
8 associated with additional hours of training, such as continuing education and required
9 annual training courses, are also paid out of the Training O&M sub-program. Full-time
10 and temporary union instructors who administer the training are also funded in this
11 sub-program.

12 **Q. How does this work benefit customers?**

13 A. This work benefits customers by ensuring the Company has enough employees with the
14 required training to have the skills to complete field work, and ensuring employees are
15 properly trained in safety procedures.

16 **Q. How much is the Company projecting to spend in the test year in this case?**

17 A. As shown in Exhibit A-124 (MPK-14), line 25, column (l), the Company is projecting to
18 spend \$15,833,000 in the test year.

19 **Q. How were these spending amounts determined?**

20 A. The expenses for this sub-program were determined based on the number of employees,
21 apprentices, and external candidates, multiplied by the expected hours training they will
22 receive each year.

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1 **Q. What is driving the increase in spending in this sub-program compared to recent**
2 **levels?**

3 A. The increase in spending is being driven by the Company's projected increased headcount
4 in its field operations workforce, which in turn increases the training expenses that must be
5 incurred.

6 **Tools**

7 **Q. What work activities are carried out in the Tools O&M sub-program?**

8 A. The Tools O&M sub-program includes the cost of procuring tools valued under \$1,000,
9 including the U.S. Department of Labor's Occupational Safety and Health Administration
10 ("OSHA") safety devices, testing equipment, and utility-specific industry tools,
11 particularly fire-retardant clothing.

12 This equipment is required to maintain, inspect, and re-calibrate the equipment on
13 Company trucks for use in the field. The Tools O&M sub-program also includes expenses
14 related to tool repairs.

15 **Q. How does this work benefit customers?**

16 A. This work enables a safer, faster response to outages, safe and efficient installation of new
17 services, and more productive completion of projects with less waste and lower unit costs.
18 In general, adequate tools are required to complete field work to improve reliability and
19 restore service. Some tools, such as fire-retardant clothing and other personal protective
20 equipment are essential for employee safety and are required by OSHA regulations.

21 **Q. How much is the Company projecting to spend in the test year in this case?**

22 A. As shown in Exhibit A-124 (MPK-14), line 26, column (l), the Company is projecting to
23 spend \$1,982,000 in the test year.

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1 **Q. How was this spending amount determined?**

2 A. This spending amount is determined based on the size of the field operations workforce,
3 which in turn determines how many tools, including fire-retardant clothing and personal
4 protective equipment, the Company needs.

5 **Q. What is driving the increase in spending in this sub-program compared to recent**
6 **levels?**

7 A. The modest increase in spending in this sub-program is being driven by the Company's
8 projected increase in its field operations workforce to support the Reliability Roadmap.

9 **Field Operations Expenses**

10 **Q. What work activities are carried out in the Field Operations Expenses O&M**
11 **sub-program?**

12 A. The Field Operations Expenses sub-program consists of the cost of overhead expenses in
13 support of the Company's in-field operations team. For electric lineworkers, substation
14 workers, and electric service workers, this sub-program covers most of their expenses
15 outside of salaries: travel expenses, meals, and field mobility costs for things like phones
16 and internet connectivity in the field.

17 **Q. How does this work benefit customers?**

18 A. This work benefits customers by enabling employees to do their jobs in the field,
19 completing reliability projects and other work that benefits customers. These expenses
20 ensure that employees can travel to where work is needed.

21 **Q. How much is the Company projecting to spend in the test year in this case?**

22 A. As shown in Exhibit A-124 (MPK-14), line 27, column (I), the Company is projecting to
23 spend \$2,608,000 in the test year.

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1 **Q. How were these spending amounts determined?**

2 A. These costs are planned annually, based on the expected costs to support an in-field
3 operations team to carry out the various activities required for supporting the safe, reliable,
4 and efficient operations of the electric distribution system. In general, projected spending
5 is heavily based on historical actuals, with adjustments based on apprentices hired that will
6 increase total headcount, and based on any increases in items such as the cost of travel and
7 telecommunications.

8 **Q. What is driving the increase in spending in this sub-program compared to recent**
9 **levels?**

10 A. The increase in spending is being driven by the Company's increased headcount in its field
11 operations workforce, which in turn increases the total expenses incurred.

12 **Supervision/Admin Staff**

13 **Q. What work activities are carried out in the Supervision/Admin Staff O&M**
14 **sub-program?**

15 A. This sub-program includes the salaries and expenses of the supervision and leadership (at
16 the first-line supervisor level) for Electric Operations, to ensure safe operation of facilities
17 and adherence to Company policies.

18 Salaries and expenses fund O&M Supervision in Electric LVD, Customer Field
19 Services, Electric System Substation, Electric System HVD, Substation Construction,
20 Electric Work Methods and Tools (governing skills training for existing workforce), and
21 the Electric Joint Committee (governing training for apprentices).

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1 **Q. How does this work benefit customers?**

2 A. This work benefits customers by funding the field supervision necessary for completing
3 work in the field, and the supervision required in certain training situations to ensure the
4 Company continues to have an adequate workforce.

5 **Q. How much is the Company projecting to spend in the test year in this case?**

6 A. As shown in Exhibit A-124 (MPK-14), line 29, column (I), the Company is projecting to
7 spend \$5,312,000 in the test year.

8 **Q. How were these spending amounts determined?**

9 A. These spending amounts were determined based on projected headcounts and the salaries
10 for those employees.

11 **Q. What is driving the increase in spending in this sub-program compared to recent
12 levels?**

13 A. The increase in spending is driven by increased number of supervisors to support the
14 growth in the workforce needed to deliver the Reliability Roadmap

15 **Grid Management – Distribution**

16 **Q. What work activities are carried out in the Grid Management – Distribution O&M
17 sub-program?**

18 A. Grid Management is responsible for providing statewide 24/7 monitoring and control of
19 the LVD and HVD systems. This includes providing statewide dispatch of electric field
20 resources to respond to electric service interruptions, electrical hazards, and other calls
21 related to electric services reported by customers. Grid Management coordinates and
22 administers planned work supporting electric reliability projects, maintenance work, and
23 customer-related work on the HVD and LVD systems. Grid Management is also

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1 responsible for the coordination of major electric service restoration efforts associated with
2 storms and other natural disasters. Lastly, Grid Management is responsible for operating
3 grid automation devices and using advanced applications to improve system reliability,
4 reduce outage duration, ensure power quality within MPSC regulations, and reduce energy
5 waste. O&M expenses in this program are for the salaries and expenses of operating and
6 support function employees at the control and dispatch centers that the Company operates.

7 **Q. How does this work benefit customers?**

8 A. This work benefits customers by allowing for the timely restoration of electric service,
9 securing and clearing of electrical hazards impacting public safety, isolating failed
10 equipment and performing partial service restorations, remotely operating field devices to
11 reduce outages during and mitigate emergency conditions impacting the system or the
12 public.

13 **Q. How much is the Company projecting to spend in the test year in this case?**

14 A. As shown in Exhibit A-124 (MPK-14), line 31, column (I), the Company is projecting to
15 spend \$4,271,000 in the test year.

16 **Q. How were these spending amounts determined?**

17 A. These spending amounts were determined based on employee salaries for the necessary
18 headcount to fill the operating and support roles in the program, representing an amount of
19 \$3,383,000. Additionally, expenses associated with each department in the program, as
20 well as annual software maintenance fees, communication maintenance costs and fees, and
21 substation communication equipment demand maintenance costs, are in the amount of
22 \$580,000. Lastly, O&M related project costs associated with the Unified Control Center

1 project as referenced in Company witness Snider's testimony are included in this program
2 in the amount of \$308,000.

3 **Underground Workforce**

4 **Q. Please describe the O&M work related to the Underground Workforce Program as**
5 **shown in Exhibit A-124 (MPK-14), line 33.**

6 A. The Underground Workforce Program is responsible for both the undergrounding work in
7 subdivisions and new business services, relocations, and reliability projects, plus future
8 undergrounding the Company expects to pursue through the Reliability Roadmap and is
9 proposing to resume in the test year of the instant case. The group can also perform
10 replacement of failed underground and new underground construction for LVD overhead
11 lines replacement.

12 **Q. What is the Company's projected test year spending level for this sub-program?**

13 A. As shown in Exhibit A-124 (MPK-14), line 32, column (1), the Company is projecting test
14 year spending of \$2,236,000.

15 **Q. How were these spending amounts determined?**

16 A. These spending amounts were determined based on the workforce necessary to perform
17 undergrounding for new business and failure work, representing an amount of \$1,106,000.
18 Additionally, it is based on the workforce necessary for future undergrounding the
19 Company expects to pursue through the Reliability Roadmap, representing \$1,130,000.

20 **F. Compliance and Controls**

21 **Q. Please describe the work related to the Compliance and Controls O&M expenses.**

22 A. Historically, Compliance and Controls O&M expenses have supported activities and
23 personnel to maintain compliance with required regulations, and to provide oversight and

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controls to contractor resources. However, the Company is not projecting any bridge period or test year spending on this line item in this case.

G. Planning and Scheduling

Q. Please describe the work related to the Planning and Scheduling Program as shown on Exhibit A-125 (MPK-15), line 40.

A. Planning and long-cycle scheduling was moved to Work Management and Customer Delivery in 2021. There is no planned spending in Distribution for the Planning and Scheduling Program for the bridge period or test year.

H. Work Management and Customer Delivery

Q. Please describe the Work Management and Customer Delivery Program as shown on Exhibit A-125 (MPK-15), line 43.

A. The Company formerly had an organization called Operations Performance, responsible for implementing process improvement and transformation projects to improve efficiency and quality.

This included business plan deployment for increased visual management, problem solving, and standard work to achieve key Company objectives of Safety, Customer Experience, On-Time Commitments, Reliability, Resiliency, and Waste Elimination. The Planning and Scheduling, Contract Administration, and Resource Planning & Closeout teams were brought into Operations Performance in February 2021, as reflected in Exhibit A-124 (MPK-14), lines 37 through 43, columns (b) and (c). This meant that Operations Performance included responsibility for weekly and long-range planning and scheduling for a variety of Electric Operations fieldwork.

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1 In March 2024, a Company reorganization led to the Operations Performance
2 organization being disbanded, with employees and work transferred elsewhere. The
3 Operations Performance Program had included technology expenses in the form of labor
4 to support field work and systems, meter reading systems, order system upgrades,
5 productivity applications, data and analytics systems, field call-out system maintenance,
6 and upgrade vendor fees. These functions related to IT were moved to the Company's IT
7 organization.

8 Functions related to industrial engineering, or "lean" processes, were also spun off
9 and are now covered in the testimony and exhibits of Company witness Richard T.
10 Blumenstock. The remaining work, largely concerned with planning and scheduling and
11 related activities, is now classified in the Work Management and Customer Delivery
12 program, which replaces Operations Performance in Exhibit A-124 (MPK-14), line 40, and
13 in corresponding lines of my other O&M exhibits.

- 14 • As it is now structured, Work Management and Customer Delivery includes
15 functions for Distribution Planning, Scheduling, Close-Out and Admin, and
16 CEM. Planning ensures the operating plan adheres to the Company's business
17 plan for Electric Operations field work.
- 18 • Scheduling ensures field crews have enough work, ready-work, and the right
19 work and resources to complete the work plan.
- 20 • The Close Out and Admin functions ensure technical documentation is accurate
21 and complete, and the costs of the work settle appropriately to the work orders.
- 22 • The CEM team is focused on meeting customer needs by providing a single
23 point of contact for customer-requested service and meter installations, and
24 alterations. CEM is responsible for ensuring all new customer service requests
25 and customer-requested alterations on the Company's distribution system are
26 coordinated from initiation through completion to meet customer expectations.

1 **Q. Please describe the O&M expenses related to the Work Management and Customer**
2 **Delivery Program.**

3 A. The Company is projecting Work Management and Customer Delivery O&M expenses of
4 \$1,917,000 the projected test year, as shown in Exhibit A-124 (MPK-14), line 43,
5 column (l). This spending level is primarily based on projected headcount in the
6 organization.

7 **I. Operations Management**

8 **Q. Please describe the Operations Management Program.**

9 A. The Operations Management Program includes the salaries and expenses for senior
10 management staff, as well as chargebacks from internal departments, specifically related
11 to the operations of the electric distribution grid. This program also includes the electric
12 portion of the reserves for incentive program accruals, injuries and damages, and electric
13 claims.

14 **Q. Please describe the O&M expenses related to the Operations Management**
15 **sub-program as shown on Exhibit A-125 (MPK-15), line 44.**

16 A. The Company is projecting Operations Management O&M expenses \$1,955,000 in the
17 projected test year, as shown in Exhibit A-125 (MPK-15), line 44, column (f).

18 The O&M projection in this sub-program is comprised of the salary and expenses
19 for certain Electric Operations leaders as well as chargebacks from Supply Chain,
20 Environmental, and Real Estate.

21 The salaries for the test year are projected using planned headcount and current
22 salary plus inflation. Additional expenses are determined using a mixture of historic
23 averages, current trends, and inflation.

1 **IX. ELECTRIC ENGINEERING AND SUPPORT**

2 **Q. What are the programs contained within the Electric Engineering O&M section**
3 **found in Exhibit A-126 (MPK-16)?**

4 A. Electric Engineering O&M is separated into the following programs:

- 5 • Engineering Support
- 6 • Electric Distribution Management
- 7 • Electric Distribution - LVD
- 8 • Electric Distribution - HVD
- 9 • Electric Distribution Strategy
- 10 • Wildfire Mitigation

11 **A. Engineering Support**

12 **Q. Please describe the Engineering Support Program.**

13 A. Expenses under this program consist of salaries and expenses for Damage
14 Claims/Prevention.

15 Damage Claims/Prevention expenses include salaries, non-exempt wages, and
16 business expenses (travel, training, contractor costs, cell phone charges, fleet chargebacks,
17 etc.) for Damage Claims and Damage Prevention employees.

18 These employees oversee the staking and locating of underground facilities in the
19 Staking O&M sub-program described earlier in my direct testimony.

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1 **Q. Please describe the O&M expenses related to Engineering Support, as shown on**
2 **Exhibit A-124 (MPK-14), line 47.**

3 A. The Company is projecting Engineering Support O&M expenses of \$1,277,000 in the
4 projected test year. This amount is based on the number of employees, and is in line with
5 the test year amount approved by the Commission in Case No. U-21585.

6 **B. Electric Distribution Management**

7 **Q. Please describe the Electric Distribution Management Program.**

8 A. The Electric Distribution Management Program expenses include salaries for the Electric
9 Distribution engineering leadership team and their support staff.

10 **Q. What is the Company's projected test year spending for the Electric Distribution**
11 **Management Program?**

12 A. As shown in Exhibit A-124 (MPK-14), line 48, column (I), projected spending for this
13 program is \$174,000 in the test year. This is in line with recent levels, and with the amount
14 approved in Case No. U-21585.

15 **C. Electric Distribution – LVD**

16 **Q. Please describe the Electric Distribution – LVD Program shown on Exhibit A-124**
17 **(MPK-14), line 49.**

18 A. Expenses in this program cover salaries and expenses for the Company's LVD Engineering
19 organization, which includes the Company's LVD Planning, LVD Design, Joint Pole
20 Rental, and Grid Automation teams.

21 **Q. Please explain LVD Planning.**

22 A. LVD Planning expenses primarily include the O&M portion of salaries, business expenses,
23 and training for LVD Planning employees. LVD Planning personnel perform security

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inspections on at least one-half of the overhead LVD system each year, and initiate corrections to defects they find. They plan, develop the scope, and initiate projects that:

- Correct LVD system planning criteria violations found by performing power flow analyses on the Company's LVD circuits;
- Improve reliability for LVD infrastructure;
- Serve C&I customer load additions connected to the LVD system; and
- Further the modernization of the distribution system.

They also support the Company's stray voltage mitigation program by performing inspections to validate proper installation and operation of the installed mitigation equipment.

Q. Please describe LVD Design.

A. LVD Design expenses primarily include the O&M portion of salaries, business expenses, and training for LVD Design personnel. These personnel create designs for connecting new C&I customers to the LVD system as well as designs for projects that improve reliability or upgrade the capacity of the LVD system.

Additionally, the LVD Design team also creates designs for relocations, third-party work such as Michigan Department of Transportation, pole attachments such as cable or communication cables, and streetlight conversions such as center suspension conversions.

Q. Please describe Joint Pole Rental.

A. Joint Pole Rental includes expenses associated with jointly using poles with other utilities (e.g., telecommunications).

Expenses include attaching electric facilities to telecommunications provider poles. Sharing poles, where possible, saves the Company money by reducing the need to solely

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1 install and maintain all Company-owned poles. Expenses are determined by contractual
2 formulas defined by Joint Use Agreements with telecommunications providers.

3 **Q. What is Grid Automation?**

4 A. The Grid Automation team consists of personnel primarily responsible for planning and
5 developing the Company's Grid Automation programs and projects, as described in the
6 testimony of Company witness McPhail.

7 **Q. What is the Company's projected spending for the Electric Distribution – LVD**
8 **Program?**

9 A. As shown in Exhibit A-124 (MPK-14), line 49, the Company is projecting Electric
10 Distribution – LVD expenses of \$11,773,000 in the test year. This is an increase from
11 earlier years, and it is largely attributable to the increased amount of LVD planning and
12 LVD design work necessary to support the increased number of LVD projects being
13 identified as part of the Reliability Roadmap. It is also attributable to increased Grid
14 Automation work to support the programs and projects described in the testimony of
15 Company witness McPhail.

16 **D. Electric Distribution – HVD**

17 **Q. Please describe the Electric Distribution – HVD Program as shown on Exhibit A-124**
18 **(MPK-14), line 50.**

19 A. The Electric Distribution – HVD Program includes salaries and expenses for the
20 distribution functions of the Company's HVD Engineering organization, including HVD
21 planning work, HVD design work, system protection, standards management, and project
22 engineering.

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1 **Q. Please explain HVD planning work.**

2 A. HVD planning expenses primarily include the O&M portion of salaries, business expenses,
3 and training for personnel performing HVD planning functions.

4 HVD planning personnel plan, develop the scope, and initiate projects that correct
5 HVD system planning criteria violations found by performing power flow analyses on the
6 Company's HVD system, and to correct HVD system issues related to poor reliability or
7 poor asset health. They plan, develop the scope, and initiate projects that:

- 8 • Improve reliability for HVD infrastructure; and
- 9 • Serve large industrial customer load additions connected to the HVD system.

10 They also perform generator interconnection studies, plan and develop the scope, and
11 initiate projects to connect DERs to the HVD system and LVD substations. HVD planning
12 O&M expenses also include payment of NERC annual dues for the Company, and
13 expenses related to helicopter inspections of the HVD system.

14 **Q. Please explain HVD design work.**

15 A. HVD design personnel create designs for connecting new industrial customers to the HVD
16 system as well as designs for projects that improve reliability or upgrade the capacity of
17 the HVD system for both lines and substation projects.

18 **Q. Please explain system protection planning work.**

19 A. System protection planning expenses primarily include the O&M portion of salaries,
20 business expenses, and training for system protection planning personnel, relay
21 maintenance costs, and relay scheme communications costs.

22 System protection planning employees are responsible for the protection systems
23 across LVD, HVD, and generation. These responsibilities include:

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- Developing the engineering specifications and standards for protection systems;
- Creating and maintaining the Company's electric short circuit models that are used when performing protective device coordination studies;
- Developing settings on protective devices installed across the Company's electric system;
- Developing maintenance programs for protection devices; and
- Ensuring compliance with applicable NERC standards.

System protection planning employees analyze electric system events that caused HVD and LVD circuits, substation components, and generating plant equipment to open via protective relay activation to ensure that fault conditions were recognized properly, and that electric system interrupting devices (like substation circuit breakers) operated correctly.

System protection planning employees also work closely with HVD planning personnel when performing generator interconnection studies to ensure interconnecting generators install proper protective relays and schemes that coordinate with Company protective relays and schemes.

Q. Please describe standards management.

A. Standards management personnel provide direction to the Engineering and Operations organizations regarding Company policy, engineering, and construction standards and materials for the distribution system. In addition, they manage the engineering records throughout their life cycle for the Company's generation and electric distribution assets. Finally, they also manage work orders for HVD materials and equipment in support of Property Accounting.

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1 **Q. What are the Company's projected test year expenses for Electric Distribution –**
2 **HVD?**

3 A. As shown in Exhibit A-124 (MPK-14), line 50, projected test year spending is \$7,199,000.
4 This is in line with recent levels, with a slight increase to account for increasing amounts
5 of planned HVD work in the Reliability Roadmap and increasing expenses for HVD
6 planning to support this.

7 **E. Electric Distribution Strategy**

8 **Q. Please describe the O&M expenses related to the Electric Distribution Strategy**
9 **Program.**

10 A. The Electric Distribution Strategy Program expenses include salaries for the Distribution
11 Strategy team, who is responsible for leading engagement activities for Distribution with
12 stakeholders throughout the state, developing the long-term strategy for the organization,
13 and helping to manage the organization's capital budget.

14 **Q. What is the Company's projected test year spending for Electric Distribution**
15 **Strategy?**

16 A. As shown in Exhibit A-124 (MPK-14), line 51, projected spending in this sub-program is
17 \$363,000 in the test year. This is in line with recent levels. Note that spending in Electric
18 Distribution Strategy may fluctuate from year to year based on hiring of consultants to
19 conduct projects such as the EJ Regression analysis that was ordered in Case Nos. U-21389
20 and U-21585.

F. Wildfire Risk Mitigation O&M

Q. Please describe the O&M expenses related to the Wildfire Risk Mitigation Program as shown in Exhibit A-124 (MPK-14), line 53.

A. These are the O&M expenses for the new Wildfire Risk Mitigation work discussed earlier in my direct testimony. The Company is projecting expenses of \$512,000 in the test year, as shown in Exhibit A-124 (MPK-14), line 53, column (I). The bridge period expenses represent an annual cost to include spending for wildfire forecasting in the Company's contract with its weather monitoring service, plus expenses to capture LiDAR imagery in high-risk areas of the system.

X. LOSS STUDY

Q. Please describe the Loss Study.

A. The purpose of this study is to allocate system energy and demand losses among the various components of the electric system by calculating a percentage Loss Factor for each component. This information is used to update loss calculations in electric rates. The 2023 Loss Study Report is shown in Exhibit A-131 (MPK-21).

XI. CRITICAL INVENTORY ISSUES

Q. What does your direct testimony address regarding critical inventory issues?

A. In Case No. U-21585, Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United (collectively "MEIU") witness John D. Albers proposed that the Commission direct the Company, in its 2025 electric rate case, to identify hardware items with long lead time and develop and propose a system for maintaining inventory of such equipment. In its final Order in Case No. U-21585, page 42, the Commission agreed with MEIU's proposal and directed the Company to "(1) identify

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1 equipment generally needed for DER and EV interconnections, such as transformers, that
2 currently have a long lead time for procurement, and (2) propose a plan for maintaining an
3 adequate inventory of that equipment to support future development.”

4 **Q. What has the Company found regarding common inventory types necessary for**
5 **interconnecting DERs and EV charging infrastructure?**

6 A. In preparing my testimony, I consulted with the Company’s internal subject matter experts
7 on DER interconnections and on EV charging infrastructure. We determined that common
8 inventory types can be grouped into several illustrative categories for both DERs and EV
9 charging infrastructure. In Figure 53 below, I am listing these categories of equipment.
10 This represents the Company’s identification of hardware items relevant for DERs and EV
11 charging infrastructure. The figure also indicates, for each category of equipment:
12 a) whether or not the Company has a long-term demand plan forecast of likely needs;
13 b) whether or not the Company has identified multiple suppliers to provide redundancy;
14 and c) whether or not the Company has a long-term contract of at least three to five years’
15 duration with at least one supplier.

FIGURE 53
CRITICAL INVENTORY FOR DERs AND EV CHARGING INFRASTRUCTURE

Group	Equipment Category	Demand Plan?	Redundant Supply?	Long-Term Contract?
DER	Class 2 Poles	Yes	Yes	Yes
	Class 3 Pole	Yes	Yes	Yes
	Class 4 Poles	Yes	Yes	Yes
	Overhead Cable	Yes	Yes	Yes
	Overhead Transformer	Yes	Yes	Yes
	Pole Top Hardware	Yes	Yes	Yes
	Reclosers	Yes	Yes	Yes
	Switches	Yes	In Process	In Process
	Underground Cable	Yes	Yes	Yes
	Underground Hardware	Yes	Yes	Yes
EVs	Class 2 Poles	Yes	Yes	Yes
	Class 3 Poles	Yes	Yes	Yes
	Overhead Cable	Yes	Yes	Yes
	Pole Top Hardware	Yes	Yes	Yes
	Underground Cable	Yes	Yes	Yes
	Underground Hardware	Yes	Yes	Yes
	3-PHASE Transformers	Yes	Yes	Yes

Q. How does the Company plan to ensure that it has adequate supply of these equipment types to meet demand?

A. As indicated in Figure 53 above, the Company has a forecast of expected demand for each category of equipment critical to interconnecting DERs and EV charging infrastructure.

For every category, the Company already has multiple suppliers available, and will have long-term contracts with each supplier by the end of the year to ensure an adequate supply is available. These three components of supply chain planning—making a demand plan, securing multiple suppliers, and establishing long-term contracts—represent the Company’s three-prong approach to its supply chain strategy. This is an industry standard approach to addressing critical inventory. The Company expects that, by following this

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three-prong approach, it will be well-positioned to meet the needs of interconnecting DERs and EV charging infrastructure.

XII. AMI METRICS

Q. Please explain the requirement to include value-focused AMI metrics and elements in electric rate case filings.

A. The Commission's March 1, 2024 Order in Case No. U-21389 stated:

As set forth in this order, and in lieu of the continued provision of future advanced metering infrastructure business case updates, Consumers Energy Company and the Commission Staff shall meet as soon as reasonably possible after the date of this order to coordinate on appropriate value-focused advanced metering infrastructure metrics and elements for the company to include in its future rate case filings.

Q. Please explain how the Company is complying with this requirement.

A. The Company met with Staff on March 25, 2024, April 11, 2024, and April 23, 2024, to coordinate appropriate value-focused AMI metrics and elements for the Company to include in its future rate case filings. During those meetings, Staff provided feedback into proposed AMI metrics and elements. The value-focused AMI metrics and elements that have currently resulted from the coordination between Staff and the Company are included in Exhibit A-133 (MPK-23).

XIII. AMI Opt-out Charges

Q. Please explain the requirement to update the AMI Opt-out Charges.

A. In Case No. U-21585, the MPSC Staff recommended the Company re-evaluate AMI Opt-out Charges and rates before the next rate case to ensure that they reflect the cost of service. In its final Order in Case No. U-21585, the Commission agreed and directed the Company to undertake this update for inclusion in the instant case.

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1 **Q. Please provide an overview of the AMI Opt-out Charges.**

2 A. The AMI Opt-out Charges are intended for customers who elect to have a non-transmitting
3 meter. By selecting this option, the customer agrees to cost-based up-front and ongoing
4 monthly charges.

5 **Q. What is included in the Upfront Charge?**

6 A. The one-time fee includes the costs associated with replacing the existing AMI meter at a
7 customer's site with a legacy non-transmitting meter.

8 These upfront costs include:

- 9 • Replace Existing Smart Meter with Legacy Non-transmitting Meter – Costs
10 associated with manually removing and replacing a smart meter with a legacy
11 meter.
- 12 • Smart Meter Deployment Exceptions Process - Systems Cost – Costs associated
13 with the exceptions process for manual metering including a highly customized
14 systems solution used exclusively for non-transmitting meters.
- 15 • Customer Support – Costs associated with responding to customer inquiries
16 about the non-standard metering alternatives, initiating the billing of up-front
17 and ongoing monthly charges, and initiating service requests for meter
18 exchanges when needed.
- 19 • Restore Premise to Standard metering – Costs associated with the manual meter
20 exchange from a smart meter to a non-transmitting meter and the potential
21 exchange back to a smart meter in the future.
- 22 • Turn on/off – Costs associated with removing a smart meter from the system
23 and adding a non-transmitting meter to the location.

24 **Q. What is included in the Monthly Meter Charge?**

25 A. The monthly charge for opting out of an AMI smart meter includes the costs associated
26 with manual inspections and readings of the meters as well as ongoing non-transmitting
27 meter costs.

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These ongoing costs include:

- Meter Reading – Costs associated with reading non-AMI smart meters each month.
- Meter Testing Program for Legacy Meters – Costs associated with the regular testing of manual meters deployed in the field, roughly 6% of deployed non-transmitting meters are tested every year.
- Re-read order – Costs associated with re-reading the manual read at the meter. This process occurs when a manual read was done and the data received identified a discrepancy or error. This can also be requested by the customer.
- Monitoring, Tracking and correcting accounts – Ongoing corrections, troubleshooting, and manual adjustments to non-transmitting meter accounts.
- Non-transmitting Meter Retention – Costs associated with the meter retention program which manually removes, returns, and tests approximately 15% of manual meters yearly.
- Meter Reader Handheld Device Purchases – Cost of purchasing, replacing, and updating handheld meter reading devices used for manual meter reads, done on a four-year cycle.
- Net of AMI and Legacy capital costs – The difference between AMI capital costs and maintenance costs and Legacy capital costs.

Q. What is the Company proposing for AMI Opt-Out Charges?

A. As shown in Exhibit A-136 (MPK-26), the Company is proposing to increase AMI Opt-out Charges to:

- Upfront Charge to replace an existing AMI meter with a Legacy Non-transmitting Meter: \$216.22 one-time fee as shown on Line 7 of Exhibit A-136 (MPK-26)
- Monthly Charge: \$3.09/month as shown on Line 7 of Exhibit A-136 (MPK-26)

Q. How do the proposed charges compare to the current AMI Opt-out Charges?

A. Figure 54 shows the current AMI Opt-out Charges compared to the proposed charges.

FIGURE 54
CURRENT COMPARED TO PROPOSED OPT OUT CHARGES

Opt Out Charge	Current	Proposed
Up Front Charge	\$123.91	\$216.22
Monthly Charge	\$3.00	\$3.09

XIV. SUMMARY

Q. Please summarize your testimony.

A. In this testimony, I have provided an overview of the Company's electric distribution system, including detailed information on the system's recent reliability, and the Company's plan to improve that reliability over the coming years.

I have explained how the Company developed its Reliability Roadmap, and how the plan provided in the Reliability Roadmap will increase investment in the distribution system to improve reliability for customers in the face of increasingly severe weather.

The Company's distribution investments will adhere to the four objectives defined in the Reliability Roadmap, going beyond reliability to ensure safety and security for employees and the public; ensure an equitable grid; and keep costs affordable for customers. By following this strategy, the Company has developed the detailed capital and O&M spending plans outlined in this testimony and the direct testimony of Company witnesses Partlan, Hayward, and McPhail.

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

JON J. KOETJE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

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1 **Q. Please state your name and business address.**

2 A. My name is Jon J. Koetje. My business address is 700 East Sternberg Road, Norton Shores,
3 Michigan 49441.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
6 where I am the Director of Engineering, Procurement, and Construction (“EPC”) Project
7 Management for Fossil Generation.

8 **Q. Please describe your educational background and work experience.**

9 A. I have a Bachelor of Science in Chemical Engineering from Michigan Technological
10 University. I earned a Master Certification in Project Management from George
11 Washington University. I am a certified Project Management Professional[®] and a licensed
12 Professional Engineer in the state of Michigan.

13 In 1983, I began employment at Sun Chemical Corporation in Muskegon, Michigan
14 as a Process Engineer eventually working my way up to Manager of Maintenance,
15 Engineering, and Reliability. My responsibilities included overseeing the maintenance,
16 engineering, and reliability departments for an organic pigments production facility.
17 My duties included management of general maintenance activities, outage planning and
18 execution, implementation of capital projects from inception through execution, start-up
19 testing and commissioning, and management of reliability that included non-destructive
20 testing and vibration analysis.

21 In 2005, I joined Consumers Energy in the Equipment Services organization, as a
22 Sr. Engineer II, where I managed the implementation of capital projects at the D.E. Karn
23 (“Karn”) and J.H. Campbell (“Campbell”) plants.

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1 In 2008, I progressed to the position of EPC Project Manager II. My
2 responsibilities in that position continued the management of capital projects at the Karn
3 and Campbell plants.

4 Between 2013 and 2020, I progressed through the project management job family
5 to the position of EPC Sr. Project Manager I, where I managed increasingly complex
6 projects and eventually a group of project managers that managed a portfolio of projects at
7 the Jackson Generation Station, Zeeland Generation Station, and Karn and Campbell
8 plants. In 2020, Consumers Energy promoted me to my current role as Director of EPC
9 Project Management – Fossil Generation where my duties include the management of
10 capital projects for the fossil portfolio.

11 **Q. Have you previously provided testimony before the Michigan Public Service**
12 **Commission (“MPSC” or the “Commission”)?**

13 A. Yes, I provided testimony concerning decommissioning, and ash disposal in the
14 Company’s 2024 Electric Rate Case, Case No. U-21585.

15 **Q. What is the purpose of your direct testimony in this proceeding?**

16 A. The purpose of my direct testimony is to present the actual 2024 expenses for the Karn
17 Units 1 and 2 and Campbell Units 1, 2, and 3 decommissioning as well as to present the
18 actual 2024 coal ash disposal costs for Karn Units 1 and 2, Campbell Units 1, 2, and 3, and
19 the Classic 7. In addition, my testimony presents updated projected decommissioning
20 expenses for Campbell Units 1, 2, and 3 consistent with the projection presented in Case
21 No. U-21585 as well as updated projected decommissioning expenses for Karn Units 1
22 and 2 between 2025 and 2026.

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1 **Q. Please describe the generating units for which the decommissioning and coal ash**
2 **disposal costs are being incurred.**

3 A. Five coal-fired units have now been approved for retirement. Karn Units 1 and 2 are two
4 plants approved for retirement, as detailed in the Company's Commission-approved 2018
5 Integrated Resource Plan ("IRP") in Case No. U-20165. Campbell Units 1, 2, and 3 have
6 also been approved for retirement, as detailed in the Company's Commission-approved
7 2021 IRP in Case No. U-21090.

8 Classic 7 includes three units at the J.R. Whiting ("Whiting") Generating Complex
9 near Luna Pier; two units at the B.C. Cobb ("Cobb") Generating Plant in Muskegon; and
10 two units at the Karn/J.C. Weadock ("Weadock") Generating Complex near Bay City.
11 While all the Classic 7 units have been decommissioned, and the Cobb and Whiting sites
12 have since been divested, the Company still has ongoing responsibility for coal ash disposal
13 costs, including ground water monitoring.

14 **Q. Please detail how your direct testimony is related to the direct testimony of other**
15 **Company witnesses.**

16 A. The projected spending associated with the Karn Units 1 and 2 Decommissioning,
17 Campbell Units 1, 2, and 3 Decommissioning, and coal ash disposal sponsored in my
18 testimony are part of the overall generation asset strategy explained and sponsored by
19 Company witness Richard T. Blumenstock. In addition, Company witness Patrick D. Daly
20 will discuss the regulatory asset treatment of the actual 2024 expenses for Karn Units 1
21 and 2 decommissioning, Campbell Units 1, 2, and 3 decommissioning, as well as coal ash
22 disposal costs for Karn Units 1 and 2, Campbell Units 1, 2, and 3, and the Classic 7.

1 **Q. Are you sponsoring any exhibits with your direct testimony?**

2 A. Yes, I am sponsoring the following Exhibits:

3 Exhibit A-139 (JJK-1) Karn Units 1&2 Decommissioning Plan

4 Expenditures;

5 Exhibit A-140 (JJK-2) Actual Coal Ash Disposal Plan Expenditures; and

6 Exhibit A-141 (JJK-3) JHC Decommissioning Plan Expenditures.

7 **Q. Were these exhibits prepared by you or under your direction and supervision?**

8 A. Yes.

9 **Q. How are the following sections of your direct testimony organized?**

0 A. My direct testimony is divided into three sections.

1 **Section I** will support the reasonableness and prudence of the actual 2024

2 decommissioning expenditures associated with Karn Units 1 and 2 as well as the updated

3 actual and projected Karn Units 1 and 2 Decommissioning Plan Expenditures between

4 2024 and 2026.

5 **Section II** will support the reasonableness and prudence of the actual Coal Ash

6 Disposals expenditures at all Company coal generation sites for 2024.

7 **Section III** will support the reasonableness and prudence of the actual 2024

8 decommissioning expenditures associated with Campbell Units 1, 2, and 3 as well as the

9 updated actual and projected Campbell Units 1, 2, and 3 Decommissioning Plan

0 Expenditures between 2024 and 2030.

OVERVIEW

Q. Please explain why the Company is presenting its actual 2024 Karn Units 1 and 2 decommissioning and coal ash disposal expenses in this proceeding.

A. The Commission issued an Order approving a settlement agreement in the Company's General Electric Depreciation Case No. U-20849 ("U-20849 Settlement"). Paragraph 3(a) of the U-20849 Settlement provides for the recording of the Karn Units 1 and 2 decommissioning costs and the ash disposal costs for the Classic 7 and Karn Units 1 and 2 as spent, to a regulatory asset. Paragraph 3(a) further states that these costs may be requested for recovery in future base rate proceedings. Specifically, Paragraph 3(a) states:

The decommissioning costs, less salvage value, related to D.E. Karn Units 1 and 2 and the ash disposal costs related to D.E. Karn Units 1 and 2 and the Classic 7 sites (i.e. the three units at the J. R. Whiting Generating Complex near Luna Pier, two units at the B.C. Cobb Generating Plant in Muskegon, and two units at the Karn/Weadock Generating Complex near Bay City) will be recorded, as spent, to a regulatory asset. The Company may request recovery in future base rate proceedings, and upon Commission determination that those costs are reasonable and prudent, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts.

Q. Has the Company previously presented its plans for the decommissioning and coal ash disposal costs for Karn Units 1 and 2 and its coal ash disposal cost for the Classic 7?

A. Yes. The Company originally presented its plans for the decommissioning and coal ash disposal costs for Karn Units 1 and 2 and its coal ash disposal cost for the Classic 7 in Case No. U-21224. The Commission-approved settlement agreement in that proceeding ("U-21224 Settlement") approved the Company's plans for decommissioning costs for

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Karn Units 1 and 2 and coal ash disposal costs for Karn Units 1 and 2 and the Classic 7.
Specifically, Paragraph 16 of the U-21224 Settlement stated:

The Commission should approve the Company's proposed D.E. Karn Units 1 and 2 decommissioning plan and the amortization of the regulatory asset associated with the Karn Units 1 and 2 decommissioning costs and the Karn Units 1 and 2 and the Classic 7 ash disposal costs. The costs associated with Karn Units 1 and 2 decommissioning will be amortized through 2031 beginning in 2024 and the Karn Units 1 and 2 and Classic 7 ash disposal costs will be amortized over 10 years beginning in 2024.

Company witness Daly discusses the establishment of the regulatory asset for these costs and the proposed amortization in his testimony. The Company most recently updated its plans for the decommissioning and coal ash disposal costs for Karn Units 1 and 2 and its coal ash disposal cost for the Classic 7 in Case No. U-21585.

SECTION I

Karn Units 1 and 2 Decommissioning Plan

Q. Why is the Company decommissioning Karn Units 1 and 2?

A. The settlement agreement approved by the MPSC in its June 7, 2019 Order in the Company's IRP, Case No. U-20165, approved the retirement of Karn Units 1 and 2 in 2023. This retirement aligns with the Company's goal (as approved in its 2021 IRP, Case No. U-21090) to end coal use to generate electricity by 2025, meet Michigan's energy needs while continuing the transition to net zero carbon emissions by 2040, and meet customer needs with 60% renewable energy 20% clean energy sources by 2035 with an increase to 40% clean by 2040.¹

¹ PA 235 of 2023 requires 80% of the Company's generation portfolio in 2035 to consist of clean energy resources. By 2040, PA 235 requires all of the Company's generation resources to consist of clean energy resources.

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1 **Q. Please discuss the Company's Karn Units 1 and 2 decommissioning plan expenses.**

2 A. The Company's decommissioning plan for Karn Units 1 and 2 originally presented in Case
3 No. U-21224 and most recently updated in Case No. U-21585 was based on an evaluation
4 of eight separate factors, including: (1) capacity replacement costs; (2) impact of recovery
5 of undepreciated book value; (3) customer rate impact analysis; (4) non-economic variables
6 such as portfolio balance, employment, and community impact; (5) effect on contractual
7 fuel obligations; (6) near-term revenue requirements; (7) conditions of existing equipment;
8 and (8) execution risk.

9 The Karn Units 1 and 2 Decommissioning Plan consists of multiple activities
10 beginning with the development of a strategic plan focusing on: stakeholder engagement,
11 workforce and community transitions, future use analysis, divestiture analysis, physical
12 transition of systems to a de-energized state, remediation of regulated materials, physical
13 demolition of the plant assets, salvage of scrap metals, remediation of all impacted areas,
14 backfill of soils to acceptable engineered specifications, restoration focused on maximizing
15 redevelopment opportunities, and completion of project closure to a brownfield standard.

16 **Q. What was the retirement date for Karn Units 1 and 2?**

17 A. Consistent with the settlement agreement approved in Case No. U-20165, the retirement
18 date was May 31, 2023. This date corresponded with the end of the Midcontinent
19 Independent System Operator, Inc. ("MISO") 2022/2023 Planning Year.

20 **Q. How were the cost projections in the Karn Units 1 and 2 Decommissioning Plan**
21 **developed?**

22 A. The projected costs consist of anticipated third-party costs as well as internal project
23 administration costs. The projected costs were presented on Exhibit A-27 (JEB-1) in Case

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No. U-21224, the Company's 2022 Electric Rate Case filing, and have been updated in each of the Company's subsequent electric rate case filings (i.e. Case Nos. U-21389 and U-21585). The most recent update was presented on Exhibit A-120 (JJK-1) in Case No. U-21585.

Q. What are the 11 major cost categories as outlined in the Company's Karn Units 1 and 2 Decommissioning Plan?

A. Exhibit A-139 (JJK-1), lines 1 through 11, column (a), identifies the 11 major cost categories associated with the Karn Units 1 and 2 Decommissioning Plan: 1) Utility Separation; 2) Decommissioning; 3) Abatement; 4) Demolition; 5) Asset Recovery; 6) Environmental; 7) Restoration; 8) Inventory Write Off; 9) Contingency; 10) Project Indirects; and 11) Interim Cost of Removal ("COR").

Q. What are the actual and projected costs as proposed in the Karn Units 1 and 2 Decommissioning Plan?

A. Table 1 below illustrates the total annual projected costs for the Karn Units 1 and 2 Decommissioning Plan based on the project schedule.

Table 1. Karn Units 1 and 2 Actual and Projected Decommissioning Costs (\$000s)

Pre – 2022 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast	2026 Forecast	Total Actual and Forecast
\$6,970	\$7,557	\$25,694	\$21,294	\$11,810	\$3,994	\$77,319

Q. What were the actual 2024 costs for Karn Units 1 and 2 decommissioning?

A. Table 2 below illustrates the actual 2024 expenditures for the Karn Units 1 and 2 decommissioning.

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Table 2. Karn Units 1 and 2 2024 Actual Decommissioning Costs (\$000s)

Activity	Projected	Actual	Variance
Utility Separation	-	247,791	(247,791)
Decommissioning	-	256,344	(256,344)
Abatement	14,750,163	5,749,772	9,000,391
Demolition	11,447,658	9,667,091	1,780,567
Asset Recovery	(7,200,000)	(3,977,582)	(3,222,418)
Environmental	7,119,982	5,157,214	1,962,768
Restoration	-	4,485,202	(4,485,202)
Inventory Write Off	-	228,443	(228,443)
Contingency	10,000,000	-	10,000,000
Project Indirects	9,429,527	4,996,328	4,433,199
Interim COR	-	(5,516,418)	5,516,418
Total	45,547,330	21,294,185	24,253,145

Exhibit A-139 (JJK-1), line (11), columns (d) and (e), further reflects these decommissioning expenses incurred in 2024 and a comparison to the projected expenditures presented in Case No. U-21224.

Q. How does the Company's decommissioning cost projection in this proceeding compare to the plan filed in Case No. U-21585?

A. The Company's decommissioning total project cost reflects a cost decrease of \$13,208,533 below the updated amount presented in Case No. U-21585 of \$90,527,610. The updated decommissioning costs are presented on Exhibit A-139 (JJK-1), lines 1 through 11 in columns (b) and (c). The actual and projected costs have been updated to reflect field conditions encountered and mitigation of risk as the project progresses as well as Utility Separation costs that were capitalized and are included in the testimony of Company

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witness Blumenstock. I will describe each of the individual cost components and the basis for the actual costs and updated cost projections separately.

Q. Please discuss the basis for the change in the decommissioning plan for Karn Units 1 and 2.

A. Two main developments contributed to the projected cost of the decommissioning plan for Karn Units 1 and 2. The first of these is the field conditions encountered as the work progressed, particularly around the abatement and coal removal activities. The second is the mitigation of risk as the project has progressed.

Q. Please describe the costs which are included in Exhibit A-139 (JJK-1), line 1, column (a): Utility Separation.

A. Utility Separation represents the construction and equipment costs that were projected to be incurred to separate the equipment and utilities that are common to Karn Units 1 and 2 and Karn Units 3 and 4. Performance of this work allows Karn Units 3 and 4 to operate independently after Karn Units 1 and 2 were retired on May 31, 2023.

Q. What were the actual 2024 Utility Separation expenses?

A. The Company's actual Utility Separation expenses for 2024 were \$247,791. This represents the portion of the Utility Separation costs that were not capitalized and are considered COR. Costs that were capitalized are included in the testimony of Company witness Blumenstock.

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1 **Q. How does the Company’s actual 2024 cost of \$247,791 for Utility Separation compare**
2 **to the projected 2024 expenses presented in Case No. U-21585?**

3 A. The Company’s cost projection for Utility Separation was \$247,791 higher than projected
4 as some work that was planned for 2024 was delayed due to equipment long lead times
5 experienced to complete Utility Separation projects.

6 **Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 2,**
7 **column (a): Decommissioning.**

8 A. Decommissioning represents the costs of both plant personnel and construction to drain
9 equipment, clean equipment, and de-energize the plant in preparation for transition to
10 Abatement, Dismantling, and Demolition (“AD&D”). This includes site separation costs
11 to isolate the plant from energized sources as well as costs to provide temporary power for
12 use during AD&D.

13 **Q. What were the actual 2024 Decommissioning expenses?**

14 A. The Company’s actual Decommissioning expenses for 2024 were \$256,344.

15 **Q. How does the Company’s 2024 actual cost of \$256,344 for Decommissioning compare**
16 **to the projected 2024 expenses presented in Case No. U-21585?**

17 A. The cost for decommissioning was \$256,344 higher than projected, as some work that was
18 planned for 2023 was delayed into early 2024 due to extension of the “Cold and Dark”
19 outage.

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1 **Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 3,**
2 **column (a): Abatement.**

3 A. Abatement costs represent construction costs to complete asbestos abatement and removal
4 of other regulated materials from the plant. This includes transportation and disposal of
5 asbestos and other regulated materials.

6 **Q. What were the actual 2024 Abatement expenses?**

7 A. The Company's actual Abatement expenses for 2024 were \$5,749,772.

8 **Q. How does the Company's 2024 actual cost of \$5,749,772 for Abatement compare to**
9 **the 2024 projected expenses presented in Case No. U-21585?**

10 A. The actual cost in 2024 for abatement was \$9,000,391 lower than projected due to material
11 re-characterization. Multiple materials that were inaccessible while the Karn Units 1 and 2
12 were operating were presumed to be asbestos for the purposes of bidding the Abatement
13 work. Many of these materials, when tested, were found to be non-asbestos.

14 **Q. Please describe the costs which are included in Exhibit A-139 (JJK-1), line 4,**
15 **column (a): Demolition.**

16 A. Demolition costs reflect the construction costs to completely dismantle and demolish the
17 plant. This includes removal and recycling or disposal of non-metallic demolition debris.

18 **Q. What were the actual 2024 Demolition expenses?**

19 A. The Company's actual Demolition expenses for 2024 were \$9,667,091.

20 **Q. How does the Company's 2024 actual cost of \$9,667,091 for Demolition compare to**
21 **the projected 2024 expenses presented in Case No. U-21585?**

22 A. Demolition expenses were \$1,780,567 lower than projected in 2024 due to adjustments in
23 schedule prioritizing Environmental and Restoration work in 2023.

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1 **Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 5,**
2 **column (a): Asset Recovery.**

3 A. Asset Recovery reflects the sale and scrap of surplus inventory.

4 **Q. What were the actual 2024 Asset Recovery credits?**

5 A. The Company's actual Asset Recovery credits for 2024 were (\$3,977,582).

6 **Q. How does the Company's 2024 actual credit of (\$3,977,582) for Asset Recovery**
7 **compare to the 2024 projected expenses presented in Case No. U-21585?**

8 A. There was a change of (\$3,222,418) reflecting adjustments in schedule prioritizing
9 Environmental and Restoration work in 2023.

10 **Q. Please describe the costs which are included in Exhibit A-139 (JJK-1), line 6,**
11 **column (a): Environmental.**

12 A. Environmental costs reflect the costs to remove and dispose of excess coal and impacted soil,
13 close the bottom ash impoundment associated with Karn Units 1 and 2, and treat water removed
14 for dewatering during Demolition activities.

15 **Q. What were the actual 2024 Environmental expenses?**

16 A. The Company's actual Environmental expenses for 2024 were \$5,157,214.

17 **Q. How does the Company's actual 2024 cost of \$5,157,214 for Environmental compare**
18 **to the projected expenses presented in Case No. U-21585?**

19 A. The actual 2024 expense reflects a decrease of \$1,962,768 due to actual bids for the bottom
20 ash impoundment closure being less than anticipated and transfer of excess coal for reuse
21 instead of landfilling.

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1 **Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 7,**
2 **column (a): Restoration.**

3 A. Restoration costs reflect the engineering costs to restore the property to final grade with
4 controlled storm water management and establish vegetation.

5 **Q. What were the actual 2024 Restoration expenses?**

6 A. The Company's actual Restoration expenses for 2024 were \$4,485,202.

7 **Q. How does the Company's actual 2024 cost of \$4,485,202 for Restoration compare to**
8 **the projected expenses presented in Case No. U-21585?**

9 A. The Restoration cost for 2024 were \$4,485,202 higher than projected due to pulling
10 Restoration work for the coal yard ahead in the schedule. In addition, more restoration
11 expense is expected to be incurred due to discovery of more residual coal than expected in
12 the coal yard.

13 **Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 8,**
14 **column (a): Inventory Write Off.**

15 A. Inventory Write Off reflects the book value of the remaining plant inventory assets that
16 cannot be sold or redeployed.

17 **Q. What were the actual 2024 Inventory Write Off expenses?**

18 A. The Company's actual Inventory Write Off expenses for 2024 were \$228,443.

19 **Q. How does the Company's 2024 actual cost of \$228,443 for Inventory Write Off**
20 **compare to the 2024 projected expenses presented in Case No. U-21585?**

21 A. The 2024 actual expense reflects an increase in expense of \$228,443 since less inventory
22 was written of in 2023 than anticipated due to limited resources to complete the inventory
23 write-off in 2023. Inventory write off was completed in early 2024.

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1 **Q. How does the Company's actual 2024 cost of \$0 for Contingency compare to the 2024**
2 **projected expenses presented in Case No. U-21585?**

3 A. There is a \$10,000,000 decrease from the projection. Contingency funds were reduced due
4 to the mitigation of risk or moved into other cost categories to cover realized risk.

5 **Q. Will amounts labeled as contingency be recorded in the decommissioning regulatory**
6 **asset?**

7 A. No. Only amounts actually spent will be recorded to the regulatory asset. To the extent
8 these contingency dollars are not spent, they would not be recorded to the regulatory asset
9 and would not be requested for recovery.

10 **Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 10,**
11 **column (a): Project Indirects.**

12 A. Project Indirects include Engineering & Supervision, Other Post-Employment Benefits,
13 Pension, and Administrative & General costs.

14 **Q. What were the actual 2024 Project Indirect expenses?**

15 A. The Company's actual Project Indirect expenses for 2024 were \$4,996,328.

16 **Q. How does the Company's actual 2024 cost of \$4,996,328 for Project Indirects compare**
17 **to the projected expenses presented in Case No. U-21585?**

18 A. The actual 2024 expense was \$4,433,199 lower than the projection due to decreases in
19 Engineering & Supervision, Other Post-Employment Benefits, Pension, and Administrative &
20 General costs.

21 **Q. Please describe the costs which are included on Exhibit A-139 (JJK-1), line 11,**
22 **column (a): Interim COR.**

23 A. Interim COR includes the COR portion of projects that were previously implemented but
24 have not been recovered in the depreciation rate case.

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1 **Q. What were the actual 2024 Project Interim COR?**

2 A. The Company's actual Interim COR expenses for 2024 were (\$5,516,418).

3 **Q. How does the Company's actual 2024 cost of (\$5,516,418) for Interim COR compare**
4 **to the projected expenses presented in Case No. U-21585?**

5 A. There was a change of (\$5,516,418) reflecting Utility Separation costs that were capitalized
6 and are included in the testimony of Company witness Blumenstock.

7 **SECTION II**

8 **Karn Units 1 and 2 and Classic 7 Coal Ash Disposal Plan**

9 **Q. Please provide an overview of the Company's Karn Units 1 and 2 and Classic 7 Coal**
10 **Ash Disposal Plan.**

11 A. The United States Environmental Protection Agency ("EPA") promulgated new national
12 criteria in 2015 to ensure coal ash facilities and management practices do not pose adverse
13 effects on health and the environment. In response, the Company developed plans to
14 protect against the risk of adverse impacts to health and the environment and to comply
15 with the new rules. Specifically, the plans included closure activities for all unlined
16 impoundments, accelerated landfill closures, and enhanced groundwater monitoring.
17 Execution of these plans demonstrate the Company's continued dedication to protecting
18 the state's natural resources and the health of surrounding communities. Since 2015,
19 Consumers Energy has completed closure of many coal ash management units including
20 all nine of its unlined impoundments. The Michigan Department of Environment, Great
21 Lakes, and Energy ("EGLE") has agreed with the completion of closure activities for the
22 nine units. Consumers Energy completed closure of its 125-acre Karn Landfill, which was

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certified by EGLE, and has completed the first year (2023) of closure cap construction on the 272-acre Weadock Landfill.

Q. Has the EPA updated the closure criteria for coal ash sites?

A. Yes. In 2024 the EPA promulgated updated criteria for coal ash sites. In response, the Company continued closure activities at the Weadock landfill consisting of importing clay fill material, as well as raising ITC's and the Company's transmission towers. Installation of liner material was delayed for up to three years while the Company determines the impact of the new rules on the Karn Weadock site, and the Weadock landfill. The Company has started to investigate the overall impact of the new rules on the Karn site, as well as the Classic 7 sites. Facility evaluation reports are due in early 2026 which will help define future projects required at the sites.

Q. What were the Company's 2024 actual coal ash disposal costs?

A. Table 3 below illustrates the total actual 2024 expenditures for the Company's coal ash disposal plan.

Table 3. 2024 Actual Coal Ash Disposal Costs (\$000s)

Site	Actuals
	2024
DE Karn	\$ 1,448,223
JC Weadock	\$ 19,796,598
BC Cobb	\$ 86,264
JR Whiting	\$ 85,824
JH Campbell	\$ 30,729,853
Total	\$ 52,146,763

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1 **Q. Have the projected coal ash disposal costs changed from the previous filing?**

2 A. No.

3 **Q. How were the Coal Ash Disposal Plan costs developed?**

4 A. Remaining coal ash disposal costs consist of long-term groundwater monitoring at Karn,
5 Weadock, Cobb, and Whiting as well as closure construction activities consisting of
6 construction of a remedial response for the Karn Landfill, design and construction of a
7 remedial response for the Karn closed Bottom Ash Pond, continued installation of a final
8 cover system to close the Weadock Landfill, addressing remedial action plan (“RAP”)
9 requirements at Campbell B-K which consists of constructing treatment wetlands and
10 beneficiating the ash in B-K, and closure certification of the Cobb Ash Ponds 0-8 and
11 Bottom Ash Pond. Groundwater monitoring activities are required by state and federal
12 regulations and are performed in accordance with hydrogeological monitoring plans
13 developed for each site in accordance with those regulations. The remedial response
14 proposed for Karn Landfill is included in a RAP that has been approved and is currently
15 being reviewed by EGLE. The Weadock Landfill has a Closure Plan that was approved by
16 EGLE facilitating the accelerated closure of the landfill at a lower elevation. The
17 Campbell B-K treatment wetlands and ash beneficiation are part of the RAP that is being
18 negotiated with EGLE, with approval expected in early 2025. Removal of ash from the
19 Cobb ash ponds was completed in accordance with an ash removal work plan for which
20 EGLE has provided its agreement. EGLE has agreed that the ash has been removed from
21 the Cobb ash ponds, but under the recently updated Resource Conservation and Recovery
22 Act (“RCRA”) rules are indicating that the berms still in place at the site will need to be
23 remediated to obtain final approval from EGLE. The Company will work with the Cobb

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1 site owner to complete an updated site closure plan for approval by EGLE in 2025. The
2 basis of costs for individual work scopes is provided below:

- 3 • All Sites Groundwater monitoring – these costs are based on existing
4 third-party costs to collect samples from existing groundwater monitoring
5 systems at each site and to analyze those samples at the laboratory. Costs also
6 include evaluation of the data to determine the potential for a release from the
7 landfill and reporting of the results.
- 8 • Weadock Landfill closure scopes of work are well prescribed; the first two
9 years of construction cost were based on contractor bids, and the remaining
10 years are estimated based on similar work that was previously performed at the
11 Karn Landfill. Site-specific items, including importation of additional fill to
12 reach adequate closure grades, have been estimated by third parties and refined
13 based on initial contractor bids. Design for relocating the electric distribution
14 towers that are currently within the landfill footprint is complete with third
15 parties providing cost estimates.
- 16 • Karn Landfill Remediation: As described above, this remedial activity has been
17 proposed to the State as part of a RAP, which was accepted by the State in July
18 2023. The costs reflected represent the selection of a permeable barrier wall,
19 the design of which was completed in 2024 and was approved by the State in
20 early 2025. Costs are based on third-party estimates for similar work.
- 21 • Campbell B-K treatment wetlands design is complete, and part of a RAP that is
22 currently being negotiated with the State. Costs for the treatment wetlands are
23 based on third-party estimates for similar work. The ash beneficiation project
24 is part of the RAP currently being negotiated with the State. Costs for this
25 project are based on bids from contractors.
- 26 • Campbell deep injection well: Due to the 2024 RCRA rules, the Steam Energy
27 Effluent Guidelines, and the closing of the Campbell plant, a disposal method
28 is required for the leachate from the dry ash landfill. Based on a feasibility
29 study, a deep injection well is the selected alternative. Costs for this project are
30 based on third-party estimates for similar work. Company witness Blumenstock
31 discusses this project in more detail in his direct testimony.
- 32 • Cobb 0-8 ash removal was completed, however EGLE has indicated that they
33 will not accept the project as complete without removing the outer berms at the
34 site. Costs for removing the berms are based on high level estimates from third
35 parties for this work.

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1 **Q. Please explain the projected coal ash disposal costs.**

2 A. As the Company explained in Case No. U-20849, the projected coal ash closure costs are
3 a result of several changes that have occurred since the Company's previous depreciation
4 case in Case No. U-17653. In April 2015, the EPA published a final rule regulating coal
5 combustion residuals ("CCRs"), such as coal ash, under RCRA. The final rule adopted
6 minimum standards for coal ash landfills and surface impoundments including operational
7 and closure standards, as well as standards for beneficially reusing and disposing of
8 nonhazardous CCR materials. Following the publication of the EPA rule, EGLE
9 determined that more prescriptive state requirements should be established for coal ash
10 facilities to align with federal requirements. In December 2018, EGLE enacted revisions
11 to its solid waste statute for coal ash units and submitted an application for a state
12 permitting program to the EPA for approval.

13 **Q. What is the status of EGLE's application for a state permitting program?**

14 A. The EPA is reviewing the state's application now, but those requirements are already
15 mandated under state statute. Compliance with those new requirements has caused the
16 projected costs to increase. In May 2024, the EPA promulgated new rules regarding
17 historic CCR materials which could impact future costs. Following publishing of those
18 rules, the Company is still reviewing the impact to planned work and revising costs
19 accordingly to comply with the rules. Where impacts are already known, the previous
20 section has addressed in terms of project descriptions. Following the completion of facility

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1 evaluation reports due in 2026, the Company will have further direction regarding impact
2 to planned work and costs.

3 **Q. What were the actual 2024 ash disposal expenditures for Karn?**

4 A. The actual ash disposal expenditures for Karn were \$1,448,223.

5 **Q. What were the actual 2024 ash disposal expenditures for Weadock?**

6 A. The actual ash disposal expenditures for Weadock were \$19,796,598.

7 **Q. What were the actual 2024 ash disposal expenditures for Cobb?**

8 A. The actual ash disposal expenditures for Cobb were \$86,264.

9 **Q. What were the actual 2024 ash disposal expenditures for Whitting?**

10 A. The actual ash disposal expenditures for Whitting were \$85,824.

11 **Q. What were the actual 2024 ash disposal expenditures for Campbell?**

12 A. The actual ash disposal expenditures for Campbell were \$30,729,863.

13 **Q. Are there potential impacts of changing environmental regulations?**

14 A. Yes. Consumers Energy continues to be subject to environmental regulations that will
15 require the Company to make additional capital expenditures for historical ash closures,
16 groundwater conditions, and effluent treatment, as well as ongoing capital expenditures for
17 maintenance of previously installed equipment. The current and reasonably anticipated
18 state and federal environmental statutes and regulations include but are not limited to: the
19 Steam Electric Effluent Guidelines, Cross State Air Pollution Rule, the Mercury and Air
20 Toxics Standards, the Michigan Mercury Rule, the Clean Water Act Section 316(b), and
21 RCRA, as previously discussed. Consumers Energy anticipates that it will continue to
22 incur costs to comply with the known and unknown environmental conditions that will
23 need to be addressed in a timely manner.

SECTION III

Campbell Units 1, 2, and 3 Decommissioning

Q. Why is the Company decommissioning Campbell Units 1, 2 and 3?

A. The settlement agreement approved by the MPSC in its June 23, 2022 Order in the Company's IRP, Case No. U-21090, approved the retirement of Campbell Units 1, 2 and 3 on May 31, 2025.² This retirement aligns with the Company's goal (as approved in its 2021 IRP, Case No. U-21090) to end coal use to generate electricity by 2025, meet Michigan's energy needs while continuing the journey to net zero carbon emissions by 2040, and meet customer needs with 100% clean energy sources by 2040.

Q. Please explain why the Company is presenting actual Campbell Units 1, 2, and 3 decommissioning in this proceeding for the period from January 1, 2024 through December 31, 2024.

A. The Commission-approved settlement agreement in the Company's 2021 IRP in Case No. U-21090 provided for the recovery of actual decommissioning spending for Campbell Units 1, 2, and 3. Specifically, Paragraph 5 of the settlement agreement stated:

The parties further agree that the Company will be permitted to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Recovery of the associated decommissioning and ash disposal costs will be treated as follows:

a. The decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3

² On May 23, 2025, the U.S. Department of Energy issued Order No. 202-25-3 ("DOE Order") requiring the Company to "take all measures necessary to ensure that the Campbell Plant is available to operate" through August 21, 2025. The DOE Order also specifies that, at the conclusion of this period, the Company will be permitted "sufficient time for orderly ramp down . . . consistent with industry practices." The Company is currently evaluating the impact of the DOE Order on its decommissioning plan and other aspects of this rate case. Until the Company is able to complete its evaluation, my testimony continues to reflect assumptions about the Campbell Plant's retirement before the date of the DOE Order.

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and the ash disposal costs related to Campbell Units 1, 2, and 3 will be recorded, as spent, to a regulatory asset; and

b. The Company may request recovery in future base rate proceedings, and upon Commission determination that the Company has incurred those costs as the result of reasonable and prudent actions, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts.

In addition, collection of these costs through depreciation rates was terminated in the Company's electric depreciation case, Case No. U-20849. Company witness Daly discusses the establishment of the regulatory asset for these costs and their proposed amortization in his direct testimony.

Q. What information is presented on Exhibit A-141 (JJK-3)?

A. Exhibit A-141 (JJK-3) presents the Campbell Units 1, 2, and 3 actual decommissioning costs for 2024, and an initial estimate for the complete decommissioning of Campbell Units 1, 2, and 3.

Q. What amount of expense for Campbell Units 1, 2, and 3 decommissioning did the Company record to a regulatory asset during 2024?

A. The Company recorded a total of \$5,243,744 of Campbell Units 1, 2, and 3 decommissioning expensed to a regulatory asset during 2024.

Q. What is the current estimate for the complete decommissioning of Campbell Units 1, 2, and 3?

A. The current Class 3 budgetary estimate for decommissioning Campbell Units 1, 2, and 3 is \$380,000,000. This is an increase of \$64,000,000 from the \$316,000,000 estimate provided in the Company's 2024 Electric Rate Case, Case No. U-51585.

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Q. What contributed to the increase in the estimated cost for Decommissioning Campbell Units 1, 2, and 3 from \$316,000,000 to \$380,000,000?

A. The items listed in the table below are the major contributors to the increase in the estimate.

Description	U-21585	Current	Delta
AD&D	\$148 million	\$165 million	\$17 million
Project Staffing	\$16 million	\$25 million	\$9 million
Project Indirect Costs	\$35 million	\$43 million	\$8 million
Risk Based Contingency	\$36 million	\$54 million	\$18 million
Recirculation Pond Closure	\$0 million	\$5 million	\$5 million
North Jetty Restoration	\$0 million	\$3 million	\$3million

Q. What activities were accomplished with the \$5,243,744 expense for the period from January 1, 2024 through December 31, 2024?

A. Project expenditures in 2024 included \$74,742 in Decommissioning cost, \$5,043,684 for Project Indirect cost, \$197,739 in Interim COR as the result of writing off the cost of projects that were initiated prior to the decision to decommission and will not be completed before the cessation of operations, and a credit of \$72,421 for Asset Recovery.

Q. In your opinion, were these costs reasonably and prudently incurred?

A. Yes.

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)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

SCOTT A. MCPHAIL II

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

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1 **Q. Please state your name and business address.**

2 A. My name is Scott A. McPhail II, and my business address is 3201 E. Court St., Flint,
3 Michigan 48506.

4 **Q. In what capacity are you employed?**

5 A. I am employed as Director of Grid Automation by Consumers Energy Company
6 (“Consumers Energy” or the “Company”).

7 **Q. What is your educational background?**

8 A. In 2008, I graduated from the University of Michigan-Dearborn with a Bachelor of Science
9 degree in Industrial & Systems Engineering. I earned a Master of Business Administration
10 from Eastern Michigan University in 2015.

11 **Q. Describe your experience and current responsibilities at Consumers Energy.**

12 A. I began my career with Consumers Energy full-time in 2003 as an engineering technician,
13 with a focus on gas distribution system design. Over the years I have held various roles
14 involved with economic analysis, revenue recovery, and the Company’s Regulatory Affairs
15 department. In 2016, I supported the rollout of the Company’s Lean operating system, the
16 Consumers Energy Way (“CE Way”). After supporting a number of business units on the
17 implementation of the CE Way, I joined the Electric Emergency Response team as the
18 Manager. My responsibilities encompassed the preparedness of the Company for storm
19 events that impact the electric grid. I have led many major restoration events for the
20 Company to ensure safe and quick restoration of customers. In April 2024, I accepted the
21 role in Grid Modernization as Director and later changed the name of the department to
22 Grid Automation. The responsibilities in my current role include overseeing the strategy,

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deployments (field devices, software systems), and integration of proven technology into business units, providing new capabilities within the Grid Automation portfolio.

Q. Have you previously provided testimony before the Michigan Public Service Commission (“MPSC” or the “Commission”)?

A. Yes, I provided testimony in the following MPSC case:

Case No. U-21585 Electric Rate Case

Q. How is your testimony organized?

A. Below is a Table of Contents outlining my testimony.

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I. Purpose and Structure

Q. What is the purpose of your direct testimony in the proceeding?

A. The purpose of my direct testimony is to provide an overview of the Company’s Grid Automation/Modernization plan, and to request approval of the projected capital expenditures to continue the implementation of that plan.

Q. How is the direct testimony structured?

A. **Section I** is the purpose and structure of the testimony.

Section II describes how the Company defines Grid Automation and provides an overview of how modernizing the grid will support the Company’s broader electric strategy and the enablement of the foundational capabilities required of a modern grid.

Section III provides an overview of Grid Automation capital investments.

Section IV discusses the Distribution Circuit Modernization (“DCM”) investment category.

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Section V discusses the Substation Modernization investment category.

Section VI discusses the Electric Distribution Asset Management investment category.

Section VII discusses the Planning Systems Modernization investment category.

Section VIII discusses the Operational Systems Modernization investment category.

Section IX discusses Weather Stations.

Section X provides a closing summary of my testimony.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-142 (SAM-1)	Bridge Period Grid Automation Projects;
Exhibit A-143 (SAM-2)	Test Year Grid Automation Projects;
Exhibit A-144 (SAM-3)	Line Sensor Reliability Benefits;
Exhibit A-145 (SAM-4)	RAMP Reliability Benefits;
Exhibit A-146 (SAM-5)	Line Regulator Controller Upgrades BCA;
Exhibit A-147 (SAM-6)	NOVA TS Comms Reliability Benefits;
Exhibit A-148 (SAM-7)	Peer-Peer Schemes Reliability Benefits;
Exhibit A-149 (SAM-8)	Recloser Modernization Reliability Benefits;
Exhibit A-150 (SAM-9)	Supplemental Line Sensors Reliability Benefits;
Exhibit A-151 (SAM-10)	Metro Modernization Reliability Benefits;
Exhibit A-152 (SAM-11)	Distribution Asset Management BCA;
Exhibit A-153 (SAM-12)	FLISR EPRI Report;
Exhibit A-154 (SAM-13)	FLISR BCA; and
Exhibit A-155 (SAM-14)	Weather Stations Reliability Benefits.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

1 **II. Introduction to Grid Automation**

2 **Q. Describe the objectives of Grid Automation and how customers benefit.**

3 A. A core objective of Grid Automation is to reduce the frequency and duration of customer
4 outages. The Company invests in grid infrastructure and adopts technologies proven
5 effective across the utility industry. This often involves upgrading to the latest generation
6 of grid equipment. Over the past several decades, advancements have led to new grid
7 equipment with fewer moving parts, enhanced sensors, and improved communication
8 capabilities, resulting in better performance. The Company's goal is to identify and
9 incorporate these proven, updated grid technologies into its standard deployment programs.
10 The Company has adopted a standardized approach to its deployment called the
11 Technology Enablement Process ("TEP"). This repeatable process benefits customers due
12 to deployment of predictable technologies that improve the customer experience through
13 fewer and shorter outages, and improved power quality.

14 In the U.S. Department of Energy study titled *Distribution Automation: Results*
15 *from the smart grid investment grant program*¹ the major findings show that Distribution
16 Automation technologies and systems achieve substantial grid impacts and benefits that
17 meet, and often exceed, pre-project expectations, including:

- 18 • Improved fault location, isolation, and service restoration capabilities
- 19 • Improved distribution system resilience to extreme weather
- 20 • More effective equipment monitoring and preventative maintenance
- 21 • More efficient use of repair crews and truck rolls

¹ Office of Electricity Delivery and Energy Reliability. (2016). *Distribution Automation: Results from the Smart Grid Investment Program*. U.S. Department of Energy.
https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf

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- Improved grid integration of selected distributed energy resources (“DER”)

Grid Automation also supports improved power quality for customers by controlling voltage through line conditioning devices. Not only is this needed to meet regulatory standards, but also because improved power quality means customer equipment can operate more efficiently, and the overall power generation supply required is conserved.

The final area of focus is to improve grid safety for the public and our co-workers, such as electric line workers. Consumers Energy’s projects aim to leverage automated and remote operations thus reducing hazard exposure of its co-workers and providing quicker response to risks that impact the public.

Q. Why did the Company change the name from Grid Modernization to Grid Automation?

A. The Company saw the need to have a very clear line-of-sight on reducing and eliminating outages that customers experience. Automating the electric grid has been a proven pathway to reach this goal. The future grid is expected to have more automation than ever before, including controlling and optimizing switching devices, voltage regulators, and DERs, to name a few.

Consumers Energy’s approach is to not only modernize to next generation equipment, but also to build in automation that improves the customer experience and avoids increased costs. The department will maintain its responsibilities to onboard the latest generation of distribution equipment and systems that are proven in the industry.

1 **Q. Please describe the TEP used at the Company.**

2 A. The TEP is a repeatable approach to design, procure, establish construction standards,
3 including necessary change management efforts, such as policy/process updates, and
4 training in advance of widespread deployment of new technology or equipment.

5 The TEP methodically works a technology through defined phases, from planning
6 to deployment. Throughout the TEP, the project team will go through the following
7 activities:

- 8 • Use case development
- 9 • Technology selection validation, operational readiness
- 10 • Field implementation

11 Technologies may build on each other or become *enablers*. Therefore, some
12 projects need to be evaluated as a ‘whole’ or the ‘end state,’ whereas other technologies
13 can be evaluated on their individual merits.

14 This TEP process is used as an initial implementation to later be deployed at scale
15 through the Company’s standard Reliability programs, such as those discussed by
16 Company witnesses Jennifer M. Partlan and Megan L. Hayward.

17 **Q. Has the TEP ever resulted against pursuing a new technology?**

18 A. Yes. The TEP is designed to determine if a technology provides customer benefits and is
19 worth pursuing. For example, a phase balancing device was investigated as it was deployed
20 at other utilities to help in situations with a long span of conductor, typically with a large
21 load at the end resulting in phase imbalance. After reviewing customer load data, it was
22 determined the problem this device would address is less of a concern on the Consumers
23 Energy system. Another area explored was a grid edge device that explored the installation

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of a device on a transformer pole connected to the secondary conductor. This was aimed at supporting Conservation Voltage Reduction (“CVR”) and providing improved power quality for customers. After performing an assessment of these devices installed in the field, it was determined the number of devices that needed to be installed to provide reasonable customer benefits did not provide sufficient benefit to support a large-scale deployment.

Q. What core initiatives comprise the Grid Automation portfolio?

A. The Grid Automation portfolio is comprised of six key pillars of work. These initiatives are:

1. Distribution Circuit Modernization
2. Substation Modernization
3. Distribution Asset Management
4. Planning Systems Modernization
5. Operational Systems Modernization
6. Weather Stations

Each of the six initiatives consists of one or multiple capital investments that are described in detail in the sections below.

Q. How does the Company’s Grid Automation plan support the broader electric strategy?

A. Grid Automation is a fundamental part of the electric distribution business. As discussed by Company witness Michael P. Kelly, Grid Automation directly supports the Company’s objective of building the grid of the future as the Company installs new technological capabilities on the distribution system. Targeted Grid Automation investments in key areas on the electric distribution system significantly improve safety, reliability/resiliency,

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1 affordability, and enable a clean, equitable grid. The Grid Automation portfolio will
2 continue to deliver on new and improved capabilities through proven technologies,
3 advanced applications, and foundational management systems.

4 **Q. How does the Company’s Grid Automation plan support the Company’s reliability**
5 **strategy?**

6 A. Grid Automation is a foundational piece of the Company’s Reliability Roadmap
7 alternatively known as the Electric Distribution Infrastructure Investment Plan (“EDIIP”),
8 which is a blueprint to strengthen the Company’s electric grid. By enhancing the ability
9 for smart meters, sensors, and automation devices to work together to monitor, isolate, and
10 automatically respond to interruptions more effectively, Grid Automation investments
11 result in reliability, resiliency, and efficiency benefits, including but not limited to:

- 12 • Providing voltage optimization to deliver energy efficiently year-round and also
13 reduce energy demand at peak times of the year
- 14 • Providing remote monitoring and visibility to see real-time power flow and
15 voltage throughout the grid
- 16 • Establishing communication with field devices, enabling real-time load
17 monitoring and fault detection
- 18 • Establishing remote control to field devices, enabling real-time settings
19 management
- 20 • Enabling remote monitoring and control of field devices to reduce the duration
21 and frequency of outages

22 As described in each investment’s section below, these investments are a core foundation
23 of the Company’s long-term plan to improve reliability and resiliency.

24 **Q. Are there any updates to the Grid Automation strategy?**

25 A. Since the creation of the Grid Modernization strategy in 2020, industry trends have
26 changed. For example, the advent of artificial intelligence (“AI”) and advancement in

1 predictive analytics is changing how the utility delivers improved service to its customers.
2 New regulatory requirements are in place, such as Federal Energy Regulatory Commission
3 (“FERC”) Order 2222 and Michigan Public Act 235 of 2022 (“PA 235”), promoting more
4 clean generation across the electric distribution system. The Company is revisiting the
5 existing strategy with an emphasis on proven technologies that reduce the numbers and
6 duration of outages that customers experience. The updated strategy will determine how
7 best to sequence investments to enable customers to realize the greatest benefits.

8 This work will enhance and accelerate the investments already made under the Grid
9 Modernization program and continues to align with the objectives in the Reliability
10 Roadmap.

11 **III. Capital Investments Summary**

12 **Q. Please describe how investments are categorized in the Grid Automation portfolio.**

13 A. As discussed by Company witness Kelly, the Company’s Grid Automation investments are
14 part of the overall Reliability Program (see Exhibit A-129 (MPK-19). The Grid
15 Automation investments detailed within this testimony fall under six categories:
16 Distribution Circuit Modernization, Substation Modernization, Electric Distribution Asset
17 Management, Planning Systems Modernization, Operational Systems Modernization, and
18 Weather Stations.

19 **Q. Are there investments that are new to the Grid Automation Portfolio?**

20 A. Yes. This testimony will describe a new investment in Remote-Capable Switches within
21 the Distribution Circuit Modernization program and will outline the need for Company
22 Weather Stations.

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1 **Q. What is the Company's total projected Grid Automation investment in this case?**

2 A. For the bridge period, the Company projects to spend \$25,691,000 as shown in Exhibit
3 A-113 (MPK-3), line 14, columns (i-k). For the test year, the Company projects to spend
4 \$17,837,000 as shown in Exhibit A-113 (MPK-3), line 14, column (l). The Company's
5 projected Grid Automation investments are explained in greater detail in the sections
6 below.

7 **Q. Please explain how the capital expenditures will be allocated across the investment**
8 **categories in the bridge period and the test year.**

9 A. The Company is projecting capital expenditures in the bridge period and test year for each
10 investment category as identified in Figure 1 below.

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FIGURE 1
GRID AUTOMATION CAPITAL EXPENDITURES (\$000)

	Bridge Period (Jan '25 - Apr '26)	Test Year (May '26 - Apr '27)
Distribution Circuit Modernization	18,057	6,250
Line Sensors	6,116	-
Voltage Regulator Controllers	10,526	5,120
NOVA TS Comms	20	-
Line Recloser Modernization	135	50
Peer-Peer Automation	895	270
Supplemental Line Sensors	60	115
Metro Modernization	305	650
Remote-Capable Switches	-	45
Substation Modernization	190	375
IP-Enabled RTU	80	105
IP-Enabled IED	110	270
Distribution Asset Management	1,740	4,050
Asset Repository	970	1,410
Asset Performance Management	770	2,640
Planning System Modernization	3,333	3,900
Load Flow Tool Upgrade	3,333	3,900
Operational Systems Modernization	2,300	2,900
Fault Location Isolation and Service Restoration ("FLISR")	2,300	2,900
Weather Stations	71	362
Weather Stations	71	362
Total	25,691	17,837

Q. What has been the historical actual spending in the Grid Automation/Modernization Program for the past five calendar years?

A. The Company's historical calendar year annual spending in the Grid Modernization Program for the past five calendar years is shown in Figure 2 below, and can also be found as shown in Exhibit A-113 (MPK-3), line 14.

FIGURE 2
HISTORICAL GRID MODERNIZATION SPENDING (\$000)

Grid Automation Sub-Program	2020	2021	2022	2023	2024
All other Sub-Programs (previously “Grid Modernization: Automation”)	43,532	51,153	39,411	25,781	14,596
Advanced Technologies Projects	21,518	23,697	13,934	3,253	5,524
Substation Comm Upgrades	7,214	(696)	(529)	4	42
Total	72,264	74,154	52,816	29,038	20,162

1 **Q. Please explain the decline in total program spend compared to historical years.**

2 A. Traditionally the Grid Automation/Modernization program included large scale
3 deployments such as Line Sensors and Voltage Regulator Controllers, as shown in the
4 bridge period in Figure 1. The Company expects to complete the deployment of Voltage
5 Regulator Controllers by 2027. Grid Automation investments focus on initial
6 implementation leveraging the TEP described above. Full scale deployments are expected
7 to occur under the Company’s traditional programs such as Reliability and Capacity
8 discussed by Company witnesses Partlan and Hayward.

9 **IV. Distribution Circuit Modernization Investments**

10 **Overview**

11 **Q. Please summarize the objectives of the DCM Initiative.**

12 A. DCM is a Grid Automation initiative integrating and deploying proven technologies
13 commonly used by other utilities that result in improved reliability and increased resiliency
14 on the Low Voltage Distribution (“LVD”) and High Voltage Distribution (“HVD”)
15 systems. This initiative is made up of two deployment projects and seven TEP projects.

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1 **Q. Please explain how the capital expenditures will be allocated across this investment**
2 **category in the bridge period and test year.**

3 A. The Company is projecting capital expenditures in the bridge period and test year for each
4 investment category as identified in Figure 13 below.

FIGURE 3
DCM CAPITAL EXPENDITURES (\$000)

Distribution Circuit Modernization Investment Category	Bridge Period (Jan '25 - Apr '26)	Test Year (May '26 - Apr '27)
Deployment Projects		
Line Sensors	6,116	-
Voltage Regulator Controllers	10,526	5,120
Technology Enablement Projects		
NOVA TS Comms	20	-
Line Recloser Modernization	135	50
Peer-Peer Automation	895	270
Supplemental Line Sensors	60	115
Metro Modernization	305	650
Remote-Capable Switches	-	45
Total	18,057	6,250

5 **Deployment Projects**

6 **Line Sensors**

7 **Q. Please summarize the objectives of the Line Sensor project.**

8 A. Line sensors are inductively charged devices installed on the overhead primary conductor
9 of the electric distribution system to remotely monitor electrical current, and detect
10 sustained, momentary, and potential faults, thereby improving the capability to respond
11 quickly and reduce customer outages. Figure 4 below is a picture of three line sensors, one
12 installed on each phase of the primary conductor.

FIGURE 4
3-PHASE LINE SENSOR INSTALLATION



1 **Q. What capabilities and benefits do Line Sensors provide?**

2 A. Line sensors provide remote monitoring capabilities that increase situational awareness of
3 the distribution system. This remote monitoring capability and use of real-time data
4 reduces outage durations by providing more transparency and awareness during outage
5 response. Line sensors also benefit the Company during planned outages by providing
6 more accurate historical data for time of day and seasonal loading values.

7 In addition to fault monitoring, these devices provide critical monitoring capability
8 of equipment that may be nearing its rated capacity.

9 Line sensor investments provide a variety of reliability and situational awareness
10 benefits. The primary line sensor benefits stem from enhanced fault detection through an
11 increased ability to accurately pinpoint the source of faults or grid disturbances. Line
12 sensor data is monitored in real-time using the AMPLE software and fed to the Advanced
13 Distribution Management System (“ADMS”) to identify the location of an outage, enabling
14 faster restoration response.

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1 Line sensors also provide key electric distribution system information such as
2 amperage, conductor temperature, phase balance, mis-phasing, and load flow direction.
3 This data is used to improve the LVD planning process by providing more accurate load
4 flow models and early indication of potentially overloaded equipment. The Load Flow Tool
5 investment discussed later in my testimony will leverage line sensor data to improve the
6 accuracy of load allocation and fault locating capabilities in CYME planning models,
7 illustrating the dependencies these investments have on each other. These enhanced load
8 models are used for capacity, reliability, and DER interconnection planning and to improve
9 the load transfer process for both planned and unscheduled outages within CYME and
10 ADMS.

11 Fault oscillography provided by line sensors is also used to verify proper
12 coordination between protective devices on the LVD system. The benefits of this remote
13 monitoring capability make line sensors critical to support and enable FLISR, discussed
14 later in my testimony.

15 The effective integration of line sensors into routine operations will result in
16 avoidance of customer minute interruption (“CMI”) estimated at 10,800,000 minutes as
17 shown in Exhibit A-144 (SAM-3). The calculation of CMI is described in Company
18 witness Partlan’s testimony.

19 In addition to the CMI benefits, there are savings associated with the reduction in
20 time related to the crew resources needed to identify and correct faulted conditions on the
21 system. The reduction in the duration of outages for customers decreases their exposure to
22 all the hazards associated with an unplanned outage, including those associated with
23 potential wildfire areas, and wire down conditions when line sensors are installed.

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1 Another line sensor benefit comes from their ability to proactively identify grid
2 disturbances expected to lead to sustained outages. Proactively responding to and repairing
3 grid issues *before* they become an unexpected outage saves the Company costs and avoids
4 customer outages altogether.

5 In 2022, the Company implemented the Reliability Analytics Monitoring Program
6 (“RAMP”) to support predictive fault analytics by analyzing waveforms and data from the
7 existing fleet of line sensors, along with outage ticket data sent to a Cloud Advanced
8 Analytics Platform (“CAAP”) software. CAAP is an AI and machine learning platform
9 that builds correlations between specific sensor waveform signatures and outage cause
10 codes, continuously building predictive models that further enhance a line sensor’s
11 capability of identifying outages before a customer experiences one.

12 The primary benefits associated with the execution of RAMP result from proactive
13 actions necessary to correct an adverse condition, whether it be equipment or vegetation
14 related, that if left uncorrected, has potential for resulting in a future outage adversely
15 affecting customers.

16 Since its implementation, RAMP has identified instances of insulator failures,
17 damaged lightning arrestors, cracked cutouts, and signs of arcing due to vegetation
18 encroachment, resulting in avoided CMI of a total of 136,998 in 2022; 147,488 in 2023;
19 and 181,059 in 2024. As detailed in Exhibit A-145 (SAM-4) RAMP is expected to avoid
20 2,466,699 additional CMI from 2025 through 2029 with a measurable and direct benefit
21 for customers. The Company has further concluded that additional benefits will be
22 achieved by scaling up the number of line sensors included in RAMP. In addition, there

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are avoided costs associated with the proactive identification of adverse conditions by Company employees versus addressing an outage in an unplanned emergent manner.

Q. How are Line Sensor locations selected and prioritized to maximize customer benefit?

A. The first step in selecting line sensor locations is to evaluate and prioritize circuits that are expected to realize the greatest benefit from deploying a network of line sensors. All distribution circuits that do not already have line sensors installed are considered. Circuit characteristics that factor into the prioritization include the historical Customer Average Interruption Duration Index (“CAIDI”), length of overhead miles, number and type of customers, circuit topology, and historical fault events. Once a prioritized list of circuits is established, individual line sensor locations are strategically selected to create zones that enhance predicted fault location precision and FLISR response.

Zones are typically around two miles in length, with sensors placed near non-communicating reclosers, switches, or critical junction points with major load bifurcation. Line sensors may also be installed at special points of interest, such as isolators, large industrial/commercial loads, or areas with dense forestry. This contributes additional benefits by providing monitoring capability to assist in resolving newly identified problems, such as overloaded equipment.

Q. What is the Company’s long-term plan for deployment of Line Sensors?

A. The Company has completed deployment of 1,000 line sensors in 2025 on the LVD system, the last year of mass deployment in which the Company expects to complete the deployment with approximately 12,000 line sensors. After 2025, additional line sensors would be added to the system as part of routine reliability and capacity investment projects,

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namely in the LVD Lines Reliability, LVD Lines Capacity, HVD Lines Reliability, and HVD Lines Capacity subprograms.

Q. Please identify the projects that will be accomplished with the requested spending level in the Line Sensor investment category.

A. The Company has identified projects for the bridge period, listed in Exhibit A-142 (SAM-1), pages 1 through 2.

Q. What is the Company's projected bridge period spending level, for which it is requesting cost recovery, for the Line Sensors investment category?

A. The Company is projecting Line Sensors capital expenditures of \$6,116,000 in the bridge period.

Q. How did the Company develop its projected costs for Line Sensor expenditures?

A. The cost for each location is estimated based on a unit cost that includes known material and unit labor costs associated with purchasing and mounting the sensor.

The estimated number of line sensors per circuit is based on a forecast model using historical sensor deployment data and specific circuit and reliability metrics. The cost for each project is the sum of the costs of each location included in the circuit. The total cost of this investment category is the sum of the individual planned project estimates. In addition to the cost of the devices and installation, the necessary software management system, known as AMPLE, that allows the line sensors to communicate back to the ADMS is included. AMPLE is expected to cost \$3,100,000. Lastly, the software cost for RAMP, at \$2,083,000, is included in the bridge period. In summary the associated costs are the cost of the line sensor devices, the labor to install the line sensor, the necessary software for the

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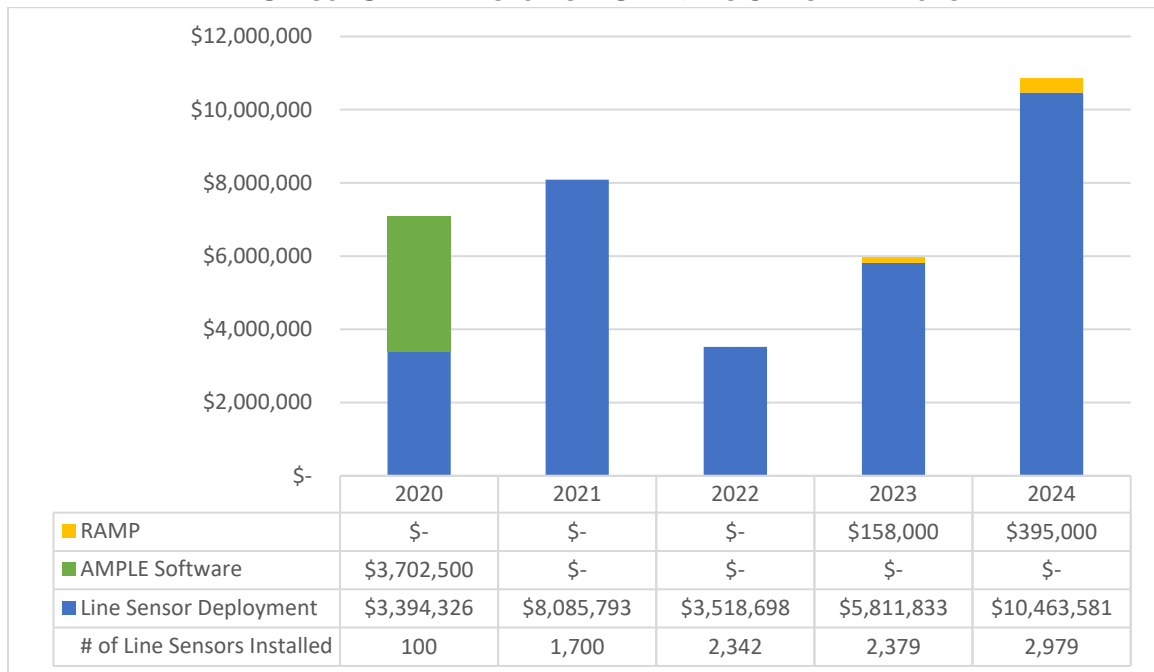
lines sensors to communicate back into the ADMS and the RAMP software to proactively address outages.

If funding is not approved for the AMPLE software, the Company will lose all communications with every line sensor rendering the devices inoperable. The AMPLE software management system is vital to maintain communications with this equipment. In future cases, it is expected this software management system will be a renewal every three-five years to maintain communications.

Q. What has been the historical actual spending for the Line Sensors investment category for the past five calendar years?

A. The Company's historical actual spending in the Line Sensors investment category for the past five calendar years is shown in Figure 5 below.

FIGURE 5
LINE SENSOR 5-YEAR HISTORICAL SPENDING & INSTALLATIONS



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1 **Q. Please explain year-over-year variation in spending in this investment category.**

2 A. There is a variance in the line sensor project annual expenditures from year to year,
3 primarily due to the timing of when materials are purchased and paid for. In some instances,
4 Line Sensor materials, in part or whole, are purchased near the end of the previous year to
5 support deployment activities scheduled to start the following year. This allows the
6 Company to be more efficient in terms of available crew resources and materials. Line
7 sensor materials can be purchased, delivered, and staged in time to support crew
8 availability and deployment schedules for any particular year. In addition, some of the
9 years may also include the purchase of the AMPLE software management and/or RAMP
10 software, which also contributes to a variance for those particular years. The unit cost for
11 line sensor locations listed in Exhibit A-142 (SAM-1) includes material and labor, but total
12 project cost also includes continuation of AMPLE software management system, as well
13 as RAMP software.

14 **Q. Does average unit cost as calculated in Exhibit A-130 (MPK-20), line 44, accurately**
15 **reflect the expected spend for an individual unit in this investment category?**

16 A. No. As described in the response above, project costs in this investment category often
17 span multiple calendar years and include costs for multiple year software packages
18 purchased at either a 3-year or 5-year interval. The variance in timing of material deliveries
19 occasionally resulted in two years of material being charged in one calendar year and
20 relatively little material the following year. The material for this investment accounts for
21 more than 75% of the total program cost, and therefore the method of taking the annual
22 cost and dividing it by the annual units completed is not an effective method for

1 understanding unit cost. Using a blended approach of considering total units and costs over
2 multiple years, levels the unit cost and accounts for the variations described above.

3 **Q. How will the projected Line Sensors expenditures support the key objectives of the**
4 **Reliability Roadmap?**

5 A. Line sensors reduce the time required to locate faults and provide predictive fault analysis
6 capabilities that then enable the Company to identify and address grid disturbances prior
7 to them becoming a sustained outage, resulting in reduced outages for customers. As
8 covered in the Reliability Roadmap, line sensors directly support proactive fault analytics
9 with RAMP and are an integral part and a key enabler of FLISR, a critical component of
10 the long-term reliability plan. In September 2023, The Liberty Consulting Group
11 (“Liberty”) completed their audit of the Company with a review of the Company’s
12 Reliability Roadmap.

13 In the Liberty Report² Part II, page 87, number 23, it was concluded that “The
14 planned installation of line sensors is sound.” Liberty’s justification was explained in the
15 report and is consistent with my testimony on the valid use case for this investment.

16 **Voltage Regulator Controllers**

17 **Q. Please summarize the capabilities and objectives of the Voltage Regulator Controllers**
18 **project.**

19 A. Voltage regulators adjust voltage on the electric distribution system based on changing
20 load conditions to ensure customers receive energy delivered within tariff-specified limits,
21 as indicated in MPSC R 460.3702 (Rule 702). Voltage regulators are remotely connected
22 through the ADMS via a communications-enabled controller, and provide dynamic

² Liberty Report Part II - <https://mi-psc.my.site.com/sfc/servlet/shepherd/version/download/068cs00000AyKapAAF>

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remote-control and monitoring capabilities for increased visibility for the Company into the electric distribution system. An example of an upgraded voltage regulator controller is shown in Figure 6.

FIGURE 6
VOLTAGE REGULATOR CONTROLLER



Q. Has the Company performed a Benefit Cost Analysis on Voltage Regulator Controllers?

A. Yes. Please see Exhibit A-146 (SAM-5) in addition to the proceeding explanation. Voltage regulators benefit customers by improving power quality and efficient energy delivery for customers impacted. The dynamic capabilities of the voltage regulator controllers support voltage efficiencies gained through the implementation of CVR and Volt-VAR Optimization (“VVO”). Through the installation of a modem and antenna in the voltage regulator controller, the Company can generate additional MWh savings with this improved visibility and control, as supported by the Department of Energy (“DOE”) report

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1 titled *Application of Automated Controls for Voltage and Reactive Power Management*,
2 published in 2012³.

3 One of the many benefits of voltage regulator controller deployment is as an enabler
4 of the CVR program, which achieves reduction of energy consumption and peak demand
5 on the electric distribution system. The CVR program and the benefits it provides are
6 discussed in more detail in the direct testimony of Company witness Partlan, as well as the
7 Company's 2021 Integrated Resource Plan ("IRP") in Case No. U-21090, which was
8 settled and approved by the Commission in 2022.

9 The two-way communication capability also avoids costs by enabling preventative
10 maintenance and proactive replacement of units approaching end-of-life. Proactively
11 replacing equipment prior to failure can prevent customer outages and improve reliability.

12 The preventative maintenance features also result in the life extension of voltage
13 regulators, further reducing costs. This remote monitoring capability also eliminates the
14 need to perform manual calendar-based inspections, a more costly and timely maintenance
15 method, thus eliminating the need to deploy field crews, which aligns with the DOE's
16 report. By incorporating the ability to remotely monitor and control the voltage regulators
17 with the installation of the modem, the Company saves on cellular costs due to the number
18 of modems, on average, being reduced per location. Most locations only require one
19 modem per voltage regulator controller in lieu of one modem per phase per location
20 because the multiphase controller only requires one modem regardless of how many phases
21 are at the location. The execution of this program has resulted in avoided costs due to the

³ Office of Electricity Delivery & Energy Reliability. (2012). *Application of Automated Controls for Voltage and Reactive Power Management*. U.S. Department of Energy.
[energy.gov/sites/prod/files/Voltage%26ReactivePower_Dec2012Final.pdf](https://www.energy.gov/sites/prod/files/Voltage%26ReactivePower_Dec2012Final.pdf)

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1 replacement of older vintage materials with newer, more efficient materials, thus avoiding
2 the emergent replacement of materials and the potential adverse effects on customer
3 voltage levels.

4 Finally, this investment benefits the Company's electric line workers through
5 reduced exposure to electrical and traffic hazards. Often these locations are on the side of
6 a roadway, requiring electric line workers to establish a safe work zone. This ability to
7 remotely monitor and operate improves the safety of Consumers Energy's workforce.

8 **Q. How are Voltage Regulator Controller investments selected and prioritized to**
9 **maximize customer benefit?**

10 A. The Company plans to upgrade all controllers on voltage regulators installed on the electric
11 distribution system. Specific voltage regulator controller locations connected downstream
12 from a Supervisory Control and Data Acquisition ("SCADA")-enabled substation have
13 been prioritized for replacement to align with and support CVR deployment.

14 **Q. What is the Company's long-term plan for deployment of Voltage Regulator**
15 **Controllers?**

16 A. The Company plans to upgrade 220 regulator locations in 2025 and complete the final year
17 of deployment with 217 regulator locations in 2026. Moving forward, as new locations are
18 added or existing locations replaced, the communicating regulator controller will be the
19 standard installation as part of the Company's reliability programs.

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1 **Q. Please identify the projects that will be accomplished with the requested spending**
2 **level in the Voltage Regulator Controller investment category.**

3 A. The Company has identified projects for the bridge period, and they are listed in Exhibit
4 A-142 (SAM-1), page 3. Projects for the test year are listed in Exhibit A-143 (SAM-2),
5 page 1.

6 **Q. What is the Company's projected bridge period and test year spending level, for**
7 **which it is requesting cost recovery, for the Voltage Regulator Controllers investment**
8 **category?**

9 A. The Company is projecting Voltage Regulator Controller capital expenditures of
10 \$10,526,000 in the bridge period, and \$5,120,000 in the test year.

11 **Q. How did the Company develop its projected costs for Voltage Regulator Controller**
12 **expenditures?**

13 A. The unit cost for a regulator location is estimated based on material and labor costs
14 associated with the number of phases, and existing health of the location. This is typically
15 driven by three key components:

- 16 • Voltage Regulator Controller & Communication Hardware – this consists of
17 either a multi-phase control, or one to three single phase controls that allow the
18 remote monitoring and control of the regulators as well as modem(s) and
19 antenna(s).
- 20 • Voltage Regulator Pole Top Hardware – based on an inspection, the estimated
21 number of tanks and other equipment that require replacement to gain full
22 functionality at that location.
- 23 • Labor Unit Costs are negotiated with the responsible Construction Contractor,
24 and each major work scope component is assigned an individual Unit Cost to
25 more effectively manage, monitor, and control labor costs associated with the
26 construction aspects of the project.

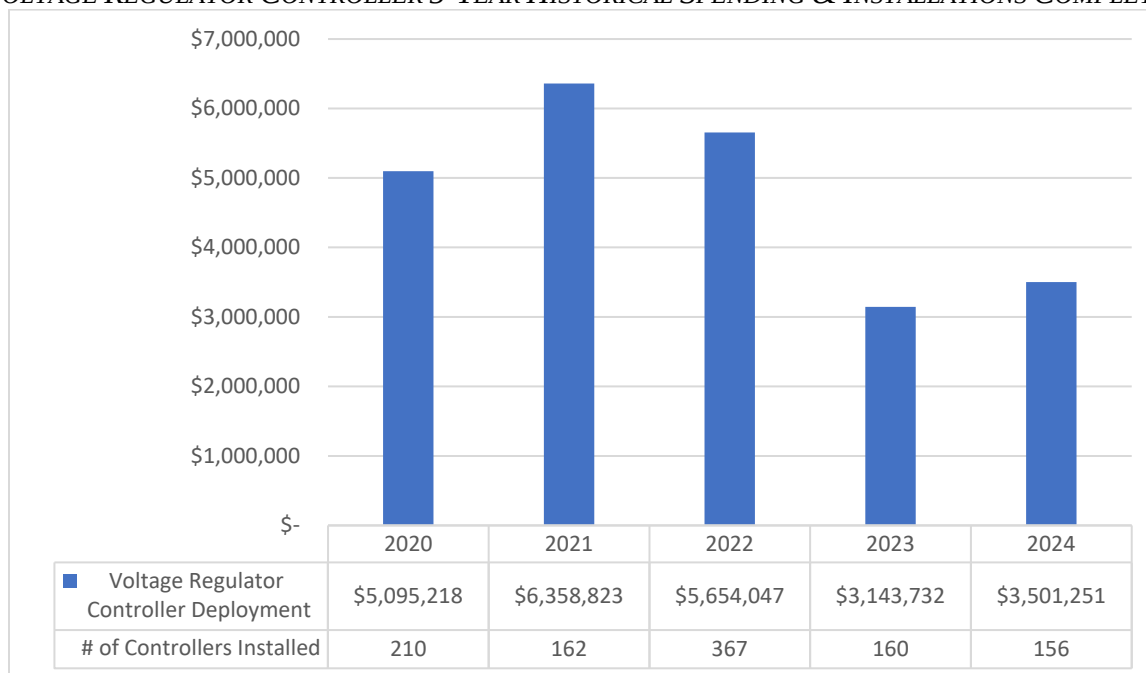
27 The cost for each work order is the sum of the cost of each location included in the work
28 order. The cost of the investment category is a sum of the cost of all the work orders.

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1 **Q. What has been the historical actual spending for the Voltage Regulator Controllers**
2 **category for the past five calendar years?**

3 A. The Company's historical actual spending in the Voltage Regulator Controllers investment
4 category for the past five calendar years is shown below in Figure 7 and is included in
5 Exhibit A-130 (MPK-20), line 45.

FIGURE 7
VOLTAGE REGULATOR CONTROLLER 5-YEAR HISTORICAL SPENDING & INSTALLATIONS COMPLETED



6 **Q. Please explain year-over-year variation in spending in this investment category.**

7 A. From 2020-2024, the five-year average spending for this investment category is
8 \$4.76 million. Variance between years during this period can be attributed to variance in
9 the number of planned locations for each year as well as instances where material is
10 purchased the year before the planned deployment to ensure the most efficient installation
11 and use of available labor resources during the first few months of the following year. In
12 addition, inflationary pressures, especially as they relate to materials, have been an
13 additional factor in this variance from year to year. The Company conducted a competitive

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1 bidding process with respect to Construction Labor for the later years of the project,
2 including 2025 and 2026. As a result of this process the Company has identified a potential
3 cost savings of about \$1.5 million with respect to Construction Labor activities related to
4 the project. The potential savings of \$3,000 per unit for each location has already been
5 incorporated into the funding request.

6 **Q. Does average unit cost as calculated in Exhibit A-130 (MPK-20), line 45, accurately**
7 **reflect the expected spend per project for this investment category?**

8 A. No. Project costs in this investment category occasionally span more than a calendar year.
9 Material for this investment is purchased in larger batches, typically several months before
10 the planned installation, to account for procurement long lead times and to ensure material
11 availability for the crews prior to the start of deployment. This allows the project to use
12 dedicated crews with a full complement of material availability. The investment category
13 has seen significant efficiencies and reduced costs using this method of construction. In
14 some years crews are allocated to start this project near or in the first quarter of the year,
15 requiring a significant amount of material be purchased the calendar year before. In other
16 years, deployment is started later in the year and the material is purchased in the same
17 calendar year as the construction. This shift in timing could result in paying for two years
18 of material in one calendar year, and a relatively minimal amount of material the following
19 year. The material for this project accounts for about 50% of the cost, and therefore the
20 method of taking the annual cost and dividing it by the annual units completed is not an
21 effective method of understanding the unit cost. Using a blended approach of considering
22 total units and costs over multiple years, levels the unit cost and accounts for the variations
23 described above. Unit costs are calculated based on historical data, contracted labor, and

material cost across all projects in the investment category without considering calendar year spend.

Q. How will the projected Voltage Regulator Controller expenditures support the key objectives of the Reliability Roadmap?

A. The Company is seeking to improve the efficiency of the electric distribution system by leveraging proven grid technologies, which includes voltage regulator controllers. This investment category is a primary component to enable the Company's CVR plans that have been highlighted in the Company's 2021 IRP. The voltage regulator controller deployment project deploys grid communication equipment, which provides increased visibility into the electric distribution system resulting in improved reliability for customers and serves as a central part of the Grid Automation investment plan, as covered in the Reliability Roadmap. In September 2023, Liberty completed their audit of the Company with a review of the Company's Reliability Roadmap. In the Liberty Report Part II, page 87, number 24, it was concluded that "The voltage regulators the EDIIP proposes are sound." Liberty's conclusion that the "expenditures are moderate and in line with what one can expect for a system like that of Consumers" supports the need for the investment described in my testimony.

Technology Enablement Projects

NOVA Triple-Single Recloser Communications Project

Q. Please summarize the objectives of the NOVA Triple-Single ("TS") Recloser Communications project.

A. The objectives of the NOVA TS Recloser Communications project are to establish an updated technology standard and build on proven technology.

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The project aims to add a communications package that can be retrofitted into existing distribution line reclosers' electronic controls, thus saving the expense of replacing the entire recloser. For comparison, a new installation of a communicating recloser (discussed below) can cost over \$70,000, but the cost per upgrade site for this project is under \$5,000. This standardization enables seamless connectivity with the ADMS. As part of the Automatic Transfer Recloser ("ATR") Loop project, the Company has already upgraded communications for a subset of reclosers connected to the grid. In that project, each ATR controller received a cellular modem. The goal of this project is to extend that successful deployment beyond ATR locations. It aims to provide remote capabilities to NOVA TS reclosers across the system. Leveraging an existing validated design package tailored for NOVA TS reclosers streamlines development. Due to the future unavailability of buying new NOVA TS reclosers, the project is also preparing the new standard SEL 651R controller (similar to the spec used for ATRs) to also be communications capable for all new installs going forward.

Q. What capabilities and benefits do you expect the NOVA TS Communications project to provide?

A. NOVA TS Communications supports situational awareness as follows:

- (1) Data can be used by the Company's outage management system to improve restoration processes.
- (2) Maintenance can be identified prior to device failures via ADMS alarms, which leads to reduced costs from avoided truck rolls via remote operation.
- (3) By bringing this data into the centralized control system, its loading and status data can be used by the power flow application to improve real-time system modeling and monitoring.

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1 These benefits contribute to avoided operating and maintenance (“O&M”) spend and
2 increased reliability. This project supports FLISR by providing remote capable reclosers,
3 which are a key enabler of wider FLISR implementation.

4 This project also supports resiliency because the remote-control capability enables
5 the Company to implement remote load transfers, which prevents truck rolls and reduces
6 the duration of outages for customers. On average, each device is projected to reduce
7 1,309 customer outage minutes per year via situational awareness and remote closing
8 capability, reducing the duration of outages. Once scaled to the whole fleet of existing
9 reclosers, the reduction of outage duration expected leads to a total avoided CMI of
10 3,256,577 from 2025 through 2033. These benefits are shown in Exhibit A-147 (SAM-6).
11 This technology can be leveraged for wildfire mitigation at a remote-capable switching
12 location to receive and quickly deploy temporary settings instructions during high-risk
13 events to mitigate the potential for spark generation.

14 Knowing the current status of the NOVA TS recloser provides a layer of safety for
15 the electric line workers, thus reducing the interaction needed with the device and lowering
16 electrical exposure. When public safety is at risk, the Company receives requests from
17 Emergency Officials such as Fire Departments to isolate sections of the circuit to protect
18 property and the public. This project will provide additional capabilities for the Company’s
19 Control Room to remotely perform this request, improving the speed of execution and
20 limiting the number of customers impacted by the request.

21 The requested investment in the bridge period is not for a full system wide
22 deployment but only the initial implementation of this technology.

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1 **Q. How are NOVA TS Communications locations selected and prioritized to maximize**
2 **customer benefit?**

3 A. The initial locations for this project are chosen to support active needs of the business for
4 a reliability project and facilitate timely field validation at these first upgraded locations.

5 **Q. What is the Company's projected bridge period spending level, for which it is**
6 **requesting cost recovery, for the NOVA TS Communications investment category?**

7 A. The Company is projecting NOVA TS Communications capital expenditures of \$20,000
8 in the bridge period.

9 **Q. How will the projected NOVA TS Communications expenditures support the key**
10 **objectives of the Reliability Roadmap?**

11 A. Introducing communications to these reclosers enhances reliability in multiple ways. First,
12 capturing monitoring data enables faster and more confident dispatching when more
13 information about an outage is known, including fault current data for fault location efforts,
14 which reduces outage restoration duration.

15 Further, remote control capabilities enable time savings via remote close
16 functionality, freeing up electric line workers to continue working on outages while the
17 Control Center expediently restores customers.

18 Lastly, alarm information enables the Company to attend to abnormal conditions or
19 failures as they occur, which reduces the likelihood of a lingering issue causing an outage
20 or increasing the impact of a nearby outage.

Peer-to-Peer Automation Scheme Project

Q. Please summarize the objectives of the Peer-to-Peer Automation Scheme project.

A. The objectives of the Peer-to-Peer Automation Scheme project are to establish a new standard solution for deploying advanced grid automation schemes, minimize outage impacts, and enable schemes with multiple sources and tie points to react dynamically to system impacts.

In a peer-to-peer scheme, local devices collaborate to determine the optimal sequence to automatically restore customers. Their goals are to minimize outage impacts to as few customers as possible and quickly restore power. This project will develop an advanced control scheme capable of operating with multiple sources and tie points. By doing so, it aims to expand distribution automation systems and identify the locations where they can be deployed. The project has evaluated vendor solutions and will begin its initial implementation in late 2025.

Q. What capabilities and benefits do you expect the Peer-to-Peer Automation Scheme project to provide?

A. The Peer-to-Peer project will support improved reliability by enabling deployment of proven ATRs in new scenarios which can handle complex circuit networks, multiple tie points, load limitations, load transfers, and the increasingly dynamic nature of the grid. These schemes will provide incremental reliability benefits to the ATR deployments discussed by Company witness Partlan. This project will result in reduced customer outage minutes projected at 41% above and beyond the ATR Loop project capabilities (Exhibit A-148 (SAM-7)), which yields an estimated annual avoided CMI at scale of 23,000,000. The project will also support resiliency by providing the Company with a wider range of

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alternatives for the ATR Loop scheme selection process; otherwise, fewer future sites will be available in the coming years, leading to fewer ATRs being installed and less customer benefit. This technology can also be leveraged for wildfire mitigation at a remote-capable switching location to receive temporary settings instructions during high-risk events.

Q. How are Peer-to-Peer Automation Scheme circuits selected and prioritized to maximize customer benefit?

A. This project plans to install one initial Peer-to-Peer scheme. The site was chosen to be a critical location to expand distribution automation in an area of high customer density with multiple tie point options and capacity constraints such that no additional automation could have been added using traditional ATR Loop planning. Future deployment will look to prioritize circuits with poor reliability, circuits with a high density of ATRs in close proximity, for which it is difficult to coordinate operations and future expansion, and circuits with ATRs that are already load-limited for transfers to ensure the Company is getting the most out of both new ATR deployments as well as existing infrastructure.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, for the Peer-to-Peer Automation Scheme investment category?

A. The Company is projecting Peer-to-Peer Automation Scheme capital expenditures of \$895,000 in the bridge period, and \$270,000 in the test year. It is important to note that the requested investments in the bridge and test period are not for a full system-wide deployment, but only the initial implementation of this technology.

1 **Q. How will the projected Peer-to-Peer Automation Scheme expenditures support the**
2 **key objectives of the Reliability Roadmap?**

3 A. ATR deployment has proven for many years to be a beneficial investment in reliability and
4 resiliency, as discussed in the Reliability Roadmap. As more ATRs continue to be added
5 to the system, the grid is becoming congested, and a solution for implementing more
6 complex ATR loop networks will be required to drive continued improvements in
7 reliability. This solution for handling complex switching solutions, using real-time loading
8 data to facilitate transfers, will help to ensure future reliability improvements are provided
9 to customers.

10 Recloser Modernization

11 **Q. Please summarize the objectives of the Recloser Modernization project.**

12 A. The objectives of the Recloser Modernization project are to update the Company standard
13 to industry-established electronic reclosers with a connection to SCADA. Doing so
14 improves reliability via enhanced situational awareness and remote control. This reduces
15 outage time, as well as adds more devices to be used by ADMS in the future. Given the
16 widespread use of hydraulic reclosers across the electric distribution system, implementing
17 this new solution has the potential to significantly improve system visibility and enhance
18 situational awareness.

19 **Q. What capabilities and benefits do you expect the Recloser Modernization project to**
20 **provide?**

21 A. This project supports reliability by introducing communication to the line recloser fleet,
22 which is foundational to expanding FLISR capabilities, improving outage restoration and
23 response, and improving safe operations by electric line workers. This project supports

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1 situational awareness and safety by providing remote visibility to these line reclosers,
2 which will enable the Company to know the status of devices from the control room and
3 communicate with field workers, reducing the time for outage restoration.

4 Reduced outage time results in improved reliability for customers and improved
5 customer experience. This project also supports resiliency by enabling remote operations,
6 which will save truck rolls, avoiding costs, and improve reliability via faster restoration by
7 avoiding the need to travel to the device. On average, it is projected each device would
8 yield a reduction of 3,160 CMI. These benefits are shown in Exhibit A-149 (SAM-8).
9 Benefit projections for a future full-scale deployment are estimated avoided CMI of
10 89,841,549 from 2025 through 2036. This technology will be leveraged in the Company's
11 Wildfire Mitigation Plan at remote-capable switching locations to receive temporary
12 settings instructions during high-risk events.

13 **Q. How are Recloser Modernization locations selected and prioritized to maximize**
14 **customer benefit?**

15 **A.** The sites chosen for this project are selected to represent various use cases and construction
16 standards to be encountered in the field to ensure the updated standard is viable across the
17 electric distribution system. These include a combination of necessary phasing and voltage
18 class construction requirements, as well as sites validating the availability of
19 communications to remote rural areas and the usefulness of communication operationally
20 to circuits with longer circuit miles or hard-to-reach areas.

1 **Q. What is the Company's projected bridge period and test year spending level, for**
2 **which it is requesting cost recovery, for the Recloser Modernization investment**
3 **category?**

4 A. The Company is projecting Recloser Modernization capital expenditures of \$135,000 in
5 the bridge period, and \$50,000 in the test year. The requested investment in the bridge and
6 test period is not for a full system-wide deployment, but only the initial implementation of
7 this technology.

8 **Q. How will the projected Recloser Modernization expenditures support the key**
9 **objectives of the Reliability Roadmap?**

10 A. Recloser Modernization introduces communications to a whole new class of protective
11 device on the distribution system.

12 Like the other recloser and sensor efforts, the monitoring data provides crucial
13 information usable by electric line workers and the Control Room to assess the scene,
14 reduce patrol time, and enable remote operations to reduce overall outage duration. Having
15 more remote-capable switching devices along main sections and branches of the electric
16 distribution system will greatly increase the ability to enact FLISR, further limiting the
17 outage to customers.

18 Supplemental Line Sensors

19 **Q. Please summarize the objectives of the Supplemental Line Sensors project.**

20 A. The primary objective of this project is to improve situational awareness of greater parts of
21 the distribution system, enabling improved reliability and operational efficiency. Existing
22 line sensors provide great benefits, but do have some technical limitations—they can
23 measure current and fault data but do not provide voltage, real power, or reactive power

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1 data. Further, there are physical limitations on distribution power lines that prevent them
2 from being installed in certain areas due to low current. As updates to this technology
3 continue to evolve, this project will incorporate the latest industry devices and tactics.

4 The project's timeline has been synchronized with the end of the existing line
5 sensor rollout to ensure alignment with technological advancements and industry best
6 practices.

7 **Q. What capabilities and benefits do you expect the Supplemental Line Sensors project**
8 **to provide?**

9 A. Line sensors currently provide significant reliability benefits, but there are limitations to
10 the types of circuits that benefit most from the existing sensor solution. There are also
11 constraints as to how many line sensors can be placed in certain locations. This project
12 will support situational awareness by introducing the potential for enabling additional grid
13 locations or to improve the type of data captured; and through providing more grid data
14 into the Company's ADMS system, situational awareness is improved for power flow and
15 outage management systems and leads to incremental reliability benefits, which reduces
16 customer outage duration. This project also supports further FLISR functionality with
17 additional locations of sensors, which would provide enhanced fault locating, improve
18 outage response via FLISR to increase reliability benefits, and further shorten customer
19 outages. Projected benefits are shown in Exhibit A-150 (SAM-9), with estimated
20 avoidance of 13,751,914 CMI from 2025 through 2033. This benefit would occur once
21 deployed on the remainder of circuits that don't have the existing line sensor solution
22 installed.

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1 **Q. How are Supplemental Line Sensors locations selected and prioritized to maximize**
2 **customer benefit?**

3 A. The initial locations for this project will be selected based on the inability of circuit
4 conditions to host the Company's present line sensors. Location selection will be balanced
5 with areas benefiting from increased data collection capabilities for both current and
6 voltage.

7 **Q. What is the Company's projected bridge period and test year spending level, for**
8 **which it is requesting cost recovery, for the Supplemental Line Sensors investment**
9 **category?**

10 A. The Company is projecting Supplemental Line Sensors capital expenditures of \$60,000 in
11 the bridge period, and \$115,000 in the test year. It is important to note that the requested
12 investments in the bridge and test periods are not for a full system-wide deployment but
13 only the initial implementation of this technology.

14 **Q. How will the projected Supplemental Line Sensors expenditures support the key**
15 **objectives of the Reliability Roadmap?**

16 A. Building on the foundational benefits of the current Line Sensor project, as described in
17 the Reliability Roadmap, this project will provide improved visibility to circuits with poor
18 reliability that are not viable candidates for the current deployment as explained in the Line
19 Sensors project section above. Doing so improves fault location efforts and reduces
20 restoration time.

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Metro Modernization

Q. Please summarize the objectives of the Metro Modernization project.

A. The Company's Metro system provides necessary power to many downtown urban areas through a network of underground vaults. Company witness Hayward provides a more detailed explanation of this critical infrastructure. The Metro Modernization project objective is to provide technology options for upgrading to an advanced Metro vault standard. Doing so will yield improved customer reliability, operational cost savings, and Metro integration into ADMS. In pursuit of this, the project will evaluate several areas: use of specialized sensors designed to detect water or gas hazards within the Metro system, assessment of switching equipment enhancements to enhance reliability and efficiency, development and integration of a communications package to facilitate seamless data exchange, and investigation of remote-control capabilities to streamline Metro operations. By establishing an updated Metro standard, the project will elevate critical electric infrastructure to industry best practices, leveraging the latest technological advancements.

Q. What capabilities and benefits do you expect the Metro Modernization project to provide?

A. Bringing vaults to a new standard that includes communication and sensing solutions enables safer and more effective operations. This project supports situational awareness by introducing monitoring and control capabilities into metro vaults, which reduces operational costs via remote operation with easier maintenance of switching equipment. Added visibility to equipment health enables proactive maintenance and inspection prior to larger failures and would lead to a further reduction in costs. This project also supports reliability by speeding up operations and outage restoration, providing shorter outages for

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1 customers. Projected benefits are shown in Exhibit A-151 (SAM-10) reporting avoided
2 CMI; while the CMI component may seem small, the Metro system hosts a
3 disproportionately larger percentage of commercial and priority customers such that
4 reducing otherwise exceedingly long outages on the Metro system significantly impacts
5 the customer experience. Further, there is a meaningful reduction in work hours totaling
6 185 hours of exposure to dangerous confined spaces to electric line workers when all vaults
7 become upgraded in the future. The improved safety benefit for Company electric line
8 workers alone necessitates this modernization investment.

9 **Q. How are Metro Modernization locations selected and prioritized to maximize**
10 **customer benefit?**

11 A. This project will target one to two vaults to upgrade initially. These sites will be chosen
12 based on use cases of likely site types typical of the Metro system. The use cases that will
13 drive site selection include sites subject to flooding and/or gas leaks to benefit from
14 environmental detection sensors to improve field worker safety, as well as sites of
15 operational importance to receive upgraded switching devices and a method to
16 communicate back to the Control Room through SCADA. It is also of note that many of
17 the Metro systems statewide all serve high-scoring environmental justice (“EJ”)
18 communities such that all Metro investments associated with this project and future
19 deployments will be providing a positive impact for those communities.

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1 **Q. What is the Company's projected bridge period and test year spending level, for**
2 **which it is requesting cost recovery, for the Metro Modernization investment**
3 **category?**

4 A. The Company is projecting Metro Modernization capital expenditures of \$305,000 in the
5 bridge period, and \$650,000 in the test year. The requested investment in the bridge and
6 test period is not for a full system-wide deployment, but only the initial implementation of
7 this technology.

8 **Q. How will the projected Metro Modernization expenditures support the key objectives**
9 **of the Reliability Roadmap?**

10 A. Providing visibility and remote-control access to Metro vaults will yield valuable
11 operational capabilities to improve reliability. Like the other projects preceding it, Metro
12 Modernization will introduce additional switching devices brought to a new standard with
13 communication. Enhanced remote and local control options will speed operations and
14 restoration. The monitoring of devices and hazard sensors also can contribute to
15 proactively addressing issues before they lead to catastrophic failures, thus avoiding
16 unnecessary equipment failure outages. Finally, introducing smart and communicating
17 equipment in vaults sets the stage for future automation schemes involving the Metro
18 system, and integration with FLISR and ADMS switching solutions—all of which
19 positively affect reliability of the Metro system, which is described in the Reliability
20 Roadmap.

Summary

Q. Please summarize how the investments described above in the DCM Initiative support the overall electric strategy and the Reliability Roadmap.

A. Described throughout the DCM Initiative and as stated in the Reliability Roadmap, there is a focus on reducing the number and duration of outages that customers experience. The Company has a standardized approach to begin deployment of proven industry technologies through its TEP. Each project shows the avoidance of CMI while improving the safety for the Company's front-line co-workers and the public.

V. Substation Modernization Investments

Overview

Q. Please summarize the objectives of the Substation Modernization ("Sub Mod") Initiative.

A. Sub Mod is a Grid Automation initiative with the primary objective of deploying advanced distribution substation technologies and updating the necessary communications within the substation. These technologies are intended to align with and enable current and future Grid Automation initiatives such as DCM, ADMS, and the increased penetration of DER. This initiative will identify and prioritize solutions that provide adaptability, interoperability, security, resiliency, and reliability to grid operations to support the grid of the future.

Sub Mod will support a future where the Company has enabled modernized communications, provided network capabilities, enhanced control infrastructure with distributed intelligence, coordinated intelligent devices and automation schemes, improved system visibility with robust data collection, and improved cyber and physical security.

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1 **Q. Please explain how the capital expenditures will be allocated across this investment**
2 **category in the bridge period and test year.**

3 A. The Company is projecting capital expenditures in the bridge period and test year for each
4 investment category as identified in Figure 18 below.

FIGURE 8
SUBSTATION MODERNIZATION CAPITAL EXPENDITURES (\$000)

Substation Modernization Investment Category	Bridge Period (Jan '25 - Apr '26)	Test Year (May '26 - Apr '27)
IP-Enabled RTU	80	105
IP-Enabled IED	110	270
Total	190	375

5 IP-Enabled Remote Terminal Unit

6 **Q. Please summarize the objectives of the Internet Protocol (“IP”)-Enabled Remote**
7 **Terminal Unit (“RTU”) project.**

8 A. The objective of the IP-Enabled RTU project is to overcome the limitations associated with
9 the existing serial-based RTU hardware and network design used by the Company by
10 enabling IP communications and integrating Field Area Network (“FAN”) equipment.
11 Currently, the RTU faces technical challenges such as (1) remote monitoring and
12 management (i.e. the inability to monitor, manage, and maintain the RTU remotely
13 impacting both cybersecurity and day-to-day operations), and (2) design complexity
14 (i.e. existing design limitations necessitating additional wiring for collecting substation
15 data, leading to increased cost and complexity). Serial technology is now becoming
16 increasingly antiquated, and the industry is moving away from supporting that
17 communication standard to Intelligent Electronic Devices (“IEDs”). Previously, the
18 Company had to address and upgrade modem standards during the 3G sunset, and it is only
19 a matter of time before serial technology also becomes unsupported in the industry and

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severely limiting technology options to better serve customers. To address these issues, the project has introduced hardware and configuration changes that have undergone rigorous testing in a controlled lab environment. These tests covered operational functionality, cybersecurity, interoperability, and engineering functionality. Having successfully completed lab testing in 2023, the project is now ready for targeted field deployment at two initial locations in 2025.

Q. What capabilities and benefits do you expect the IP-Enabled RTU project to provide?

A. The IP-Enabled RTU project will bring digital communications to the substation, setting up the framework for the IP-Enabled IEDs and Common Substation Platform. These units enable the delivery of the following capabilities for upgrading distribution substations:

- Data Network Security
- Improved Operator Efficiency
- Enhanced Situational Awareness
- Standards Based Designs and Data Communications
- Remote Engineering Access
- Configuration & Firmware Management

Ultimately, not pursuing this enhancement will leave critical substation communications infrastructure stuck with antiquated serial protocols that may lead to increased incompatibilities with modern hardware, and a potentially costly and/or urgent need to update on a less convenient and more aggressive schedule if establishing this deployment is deferred. A safety benefit is the reduced electrical exposure at high voltages for the Company's front-line work force. Today, electric substation workers must enter into the substation fencing to perform their tasks of updating firmware and adjust settings. Remote

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Engineering Access through this device will eliminate the need to perform those tasks onsite.

Q. How are IP-Enabled RTU locations selected and prioritized to maximize customer benefit?

A. The initial deployment locations were selected to confirm the capabilities described above and to be locally accessible to the resource groups in Jackson, MI. These locations represent distribution substations with a current standard RTU that supports remote engineering, automated monitoring, and cyber security requirements. Additional consideration was given to locations where the SCADA cabinet included ample space for the additional FAN communications equipment.

Q. What is the Company's projected bridge period and test year spending level, for which it is requesting cost recovery, for the IP-Enabled RTU investment category?

A. The Company is projecting IP-Enabled RTU capital expenditures of \$80,000 in the bridge period, and \$105,000 in the test year. It is important to note the requested investment in the bridge and test period is not for a full system-wide deployment, but only the initial implementation of this technology.

Q. How will the projected IP-Enabled RTU expenditures support the key objectives of the Reliability Roadmap?

A. IP-Enabled RTUs are the first foundational technology enhancement to substations that will be built upon in the coming years. Once fully realized, the capabilities of the substation of the future will provide benefits to many areas including reliability, grid security, and safety. As the devices on the electric distribution system become smarter and more interconnected, it is crucial that distribution substations keep up with that trend and can be

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1 an important part of the integrated solutions to come. This project is a critical first step to
2 achieving that capability.

3 IP-Enabled IED

4 **Q. Please summarize the objectives of the IP-Enabled IED project.**

5 A. The objective of the IP-Enabled IED project is to overcome limitations associated with the
6 existing hardware and network design of additional IEDs.

7 An IED can include regulators, reclosers, and transformer bank monitoring
8 equipment. These IEDs currently lack the capability to connect and communicate over IP
9 networks, which hinders their integration into the FAN. This TEP project will deploy new
10 hardware into the substation allowing the communication of IEDs back into the Control
11 Room and across Engineering departments.

12 **Q. What capabilities and benefits do you expect the IP-Enabled IED project to provide?**

13 A. This project builds on the infrastructure set up in the IP-Enabled RTU project. There are
14 additional data points and logs available within the substation devices that cannot be pulled
15 remotely now or even through an upgraded RTU.

16 A major benefit to IP-enabled IEDs is that retrieval of this information will be
17 instantaneous and avoids the cost and risk of dispatching an electric substation worker to
18 the substation site to download the information, reducing truck rolls and improving
19 co-worker safety. Similar to IP-Enabled RTUs, a safety benefit is the reduced electrical
20 exposure at high voltages for the Company's front-line work force. Today, Utility Workers
21 must enter the substation to perform their tasks of pulling log data. With a FAN established,
22 as detailed in the IP-Enabled RTU section, Remote Engineering Access is available. This
23 will eliminate the need to perform those tasks onsite.

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1 **Q. How are IP-Enabled IED locations selected and prioritized to maximize customer**
2 **benefit?**

3 A. The IP-Enabled IED project plans to use existing IP-Enabled RTU locations. This
4 approach provides the Company with the opportunity to integrate learnings from both
5 projects and demonstrate use case capabilities and continuity. These locations represent a
6 large (six distribution circuit) and a smaller (two distribution circuit) substation with
7 multiple current standard control types that will support remote engineering, automated
8 monitoring, and cyber security requirements.

9 **Q. What is the Company's projected bridge period and test year spending level, for**
10 **which it is requesting cost recovery, for the IP-Enabled IED investment category?**

11 A. The Company is projecting IP-Enabled IED capital expenditures of \$110,000 in the bridge
12 period, and \$270,000 in the test year. It is important to note the requested investment in the
13 bridge and test period is not for a full system-wide deployment, but only the initial
14 implementation of this technology.

15 **Q. How will the projected IP-Enabled IED expenditures support the key objectives of**
16 **the Reliability Roadmap?**

17 A. This project will provide immediate access to logs, event data, and other detailed
18 information concerning substation equipment to enable predictive failure analysis. The
19 ability to perform analysis in real-time based on data across key substation equipment will
20 enable the identification of imminent failures or the need for repairs *before* an outage
21 occurs. It also enables faster diagnosis into the reason for failures during an outage. Both
22 will reduce or eliminate outages related to substation equipment, and will reduce costs and
23 large-scale customer outages that stem from emergent repairs.

Summary

Q. Please summarize how the investments in this category support the overall electric strategy and the Reliability Roadmap.

A. The Sub Mod initiative is a foundational enabler of multiple other Grid Automation projects. With the rise of DER, electric vehicles (“EVs”), and grid-edge communication, it is important and necessary to upgrade core systems to be able to integrate, translate, and communicate with the growing amounts of data.

IP-enabled communication with grid critical assets provides future flexibility and ensures strong physical and cyber security. Technology deployments, like those outlined in this section, are critical to delivering benefits for current Grid Automation work, such as the suite of DCM projects and for future efforts related to DER optimization.

VI. Electric Distribution Asset Management

Overview

Q. Please summarize the objectives of the Electric Distribution Asset Management (“DistAM”) Initiative.

A. DistAM is the application of asset management principles and processes to electric distribution assets to maximize the usefulness and realization of value over their lifecycle, resulting in improved reliability through reduced equipment failure.

DistAM will develop lifecycle management capabilities by collecting key asset data (e.g. age, nameplate data, location, work orders) to drive a risk-informed, value-based decision-making methodology to manage and optimize asset investments. The components within DistAM will collect distribution asset data into a single centralized

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1 database that provides enhanced integration into asset health performance analysis, and
2 investment strategy platforms.

3 Key objectives within DistAM are to improve the Company's capital efficiency and
4 asset maturity levels. With increased asset maturity we will leverage advanced risk
5 analytics to create asset health scores, essential for optimizing investment planning
6 scenarios, and addressing outages before they happen. This work is aligned with industry
7 best practices defined in ISO 55000(1), as well as from the Michigan Infrastructure Council
8 Asset Management Program.

9 **Q. Please describe the DistAM Approach.**

10 A. The Company developed a DistAM strategy with key workstreams: Asset Repository
11 ("AR"), Asset Performance Management ("APM"), and Asset Investment Planning
12 ("AIP") (now complete).

13 Utilities without a structured asset management approach still accomplish ad hoc
14 and reactive asset management tasks; however, this stopgap approach will not provide the
15 same customer benefits and desired system performance. Rather, it will continue to drive
16 increased system costs based on the lack of capability for data-driven decisions and
17 planning.

18 DistAM is distinct from ADMS because it focuses on the lifecycle asset
19 management rather than real-time operational management of assets. Asset management
20 typically requires data that is collected and visualized over long-time scales. Consequently,
21 DistAM informs decisions over the medium-to-long term as opposed to ADMS's
22 short-term operational decision-making.

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1 **Q. Please explain how the capital expenditures will be allocated across this investment**
2 **category in the bridge period and test year.**

3 A. The Company is projecting capital expenditures in the bridge period and test year for each
4 investment category as identified in Figure 19 below.

FIGURE 9
DISTRIBUTION ASSET MANAGEMENT CAPITAL EXPENDITURES (\$000)

Distribution Asset Management Investment Category	Bridge Period (Jan '25 - Apr '26)	Test Year (May '26 - Apr '27)
Asset Repository	970	1,410
Asset Performance Management	770	2,640
Total	1,740	4,050

5 **Q. How much has the Company invested in the DistAM program to date?**

6 A. Since the launch of DistAM, the Company has invested \$7.9 million as of March 31, 2025.
7 The AIP was launched in 2024 and consisted of \$5.8 million. Since the launch of this
8 project, \$2.1 million has been spent on the AR and nothing has been spent on the APM as
9 of March 31, 2025. The Commission originally approved the DistAM project in Case No.
10 U-20697 and re-approved in the December 22, 2021 Order in Case No. U-20963. The
11 concept approval at that time projected an estimated \$12 million for the project. This is the
12 amount the Commission discussed in its Case No. U-21585 Order, stating that approval of
13 increased costs would require updated data.

14 **Q. How much is the Company proposing to spend on the DistAM program through the**
15 **test year in this case?**

16 A. Including the prior investment through the test year, the Company's current total projected
17 spend for the DistAM program is \$13.6 million.

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1 **Q. Please explain why costs have increased from the original projected \$12 million for**
2 **this project.**

3 A. Through the purchase and implementation of the AIP in 2024 and continued build out of
4 the AR, more refined costs are now known to build a DistAM solution. As the project
5 advanced, the Company discovered the need for the expansion of additional IT applications
6 that were not initially scoped. Reviews were conducted on the quality of the Company's
7 data and determined it would not meet the requirements of a vendor provided solution for
8 an APM. The initial approach of the Company was to purchase the APM solution and
9 implement similar to the AIP. However, as the Company's asset maturity continues to
10 improve, it was deemed a better value to build an internal APM solution that will meet
11 most of the requirements. It is estimated a vendor provided solution for an APM would
12 cost \$7.5 million to implement in year one with an estimated \$1 million annual software
13 as a solution agreement. Instead, the Company will build its own APM, estimated at \$4.2
14 million with no software agreement cost. As assets are brought into the AR, this internal
15 APM will be able to accommodate each new asset as it becomes available. My testimony
16 below will describe in more detail what is left to complete within the test period with regard
17 to AR and APM.

18 Asset Repository

19 **Q. Please summarize the objectives of the AR.**

20 A. The AR provides a single, centralized database to store essential distribution asset data.
21 The AR identifies and structures asset relationships including asset grouping, parent-child
22 relationships, and organization hierarchies. For example, it can identify the relationships
23 between a voltage regulator, the voltage regulator controller, and the cellular modem so

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these three components can be evaluated (risk-assessed) together. Grouping related equipment drives cost efficiencies by ultimately allowing for the bundling of work at the same locations. Maintaining an AR facilitates sharing of asset information across multiple software, systems, and third-party applications. A major component of the implementation of an AR is the software and data integration. The AR provides the APM and the AIP tools a single source of truth for asset information eliminating redundancy and inaccuracy. Along with the software and data integration, the AR also has the objective to collect comprehensive and accurate data on major electric distribution assets. Drone flights and imaging have been added to collect the comprehensive and accurate data on distribution assets across select circuits.

Q. What capabilities and benefits do you expect the AR to provide?

A. DistAM is an essential part of the Company's broader initiative to maximize reliability and resiliency by optimizing how the electric distribution system is proactively maintained and managed. The AR enhances the Company's asset life-cycle processes, data, imaging, and technology, allowing for improved capture and analysis of asset health details, which will lead to more optimized investment planning scenarios. The primary benefits of DistAM include:

- Reduced capital and maintenance costs
- Reduced customer outages and restoration costs
- Reduced power quality issues and system losses
- Increased asset availability
- Reduced asset degradation risk
- Improved resilience of the electric distribution system
- Improved asset maturity

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- Imaging

A centralized asset repository improves work efficiency by avoiding the need to manage across various software to pull and analyze data. In addition to improved efficiency, this tool provides the ability to complete advanced risk analytics to create asset health scores. The benefits of the AIP and APM would not be fully realized without a robust asset repository feeding consistent, comprehensive data. DistAM will use smart grid technologies to effectively coordinate the use of devices, the data they consume, and the information they produce, supporting all other Grid Automation capabilities in delivering benefits to customers.

A comprehensive BCA is provided for the DistAM as a whole in Exhibit 152 (SAM-11), including all necessary components of AR, APM, and AIP.

It is important to note the analysis performed in the BCA is on the full implementation of DistAM across all in-scope electric assets. The requested investment in the bridge period and test year does not include the full system costs. Future rate cases will request the needed funding to complete the full implementation of this technology. Exhibit A-152 (SAM-11) contains the estimated total costs across the life of the DistAM program.

Q. What electric distribution assets will be considered within the AR?

A. The AR will consider all major electric distribution assets on both the HVD system and LVD system. Examples of the assets that will be considered in the AR include:

- Equipment installed on the Company's HVD lines, including but not limited to poles, switches, insulators, and conductors;
- Equipment installed within distribution substations, including but not limited to transformers, regulators, reclosers, breakers, and relays; and
- Equipment installed downstream from the distribution substation fence, including but not limited to poles, conductors, transformers, capacitors, voltage regulators, metro equipment, and isolators.

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1 In total, seven electric assets are planned to be included by the end of 2025 with a total of
2 19 assets planned for by the end of 2027.

3 **Q. How will assets be selected and sequenced to maximize customer benefits?**

4 A. The Company plans to integrate an array of distribution assets into the AR, APM, and AIP
5 over time. These assets will be added in an iterative fashion to reduce complexity and use
6 learned efficiency gains. The Company will use several metrics to sequence the order
7 assets are integrated to help maximize customer benefits.

8 Three primary metrics will be used to sequence asset integration: customer and
9 reliability impact, data availability, and complexity. These metrics help describe the
10 Company's asset maturity.

11 Reliability Metric: The reliability benefit metric will be used to consider the amount
12 of value generated by improving asset management practices for the asset. Assets
13 with a high reliability benefit have a significant impact to system reliability and
14 customer outages if they fail or perform poorly.

15 Data Availability Metric: The data availability metric considers the availability of
16 high-quality data that can be used to evaluate asset health. Assets with limited data
17 will be more difficult to integrate and optimize.

18 Complexity Metric: The complexity metric is used to consider the quantity and
19 difficulty with technically integrating asset data from various source systems into
20 the AR. Some assets will require data from many diverse systems to develop an
21 accurate health score, while other assets may be evaluated with a limited number
22 of simple integrations. Likewise, the quantity of assets and their associated data
23 points may vary from hundreds to thousands to millions with escalating complexity.

24 By evaluating each asset and scoring it based on these evaluation metrics, the Company
25 has developed an asset integration strategy that maximizes customer benefits.

26 **Q. How will the projected expenditures support the key objectives of the Reliability
27 Roadmap?**

28 A. The AR is the foundational component of the broader DistAM strategy. To enhance the
29 ability to proactively monitor and replace assets prior to creating an outage, the Company

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1 needs a system that tracks and structures the data in a methodical approach. The AR
2 provides that standardization and is an enabler of the many beneficial reliability programs
3 that follow, including AIP and APM. As covered in the Reliability Roadmap, the DistAM
4 program is an essential part of the Company's broader initiative to maximize reliability and
5 resiliency by optimizing how the electric distribution system is proactively maintained and
6 managed to increase reliability for customers.

7 Asset Performance Management (APM)

8 **Q. Please summarize the objectives of APM.**

9 A. APM encompasses the capabilities of data capture, integration, visualization, and analytics
10 tied together to improve the reliability and availability of physical assets. The APM is a
11 software tool that leverages the base of asset data made available from the AR to develop
12 a health index or a health score for assets across electric distribution. This tool will use
13 advanced algorithms to develop health and risk monitoring through a standard and common
14 interface for Company employees to generate, monitor, and make decisions for identifying
15 opportunities to address assets requiring attention based on asset health and risk. It is
16 expected that these asset health and risk scores will be incorporated into the Company's
17 Quarterly Operating Review ("QOR") as discussed by Company witness Kelly.

18 **Q. What capabilities and benefits do you expect APM to provide?**

19 A. APM will enable the Company to monitor asset health and risk enabling
20 reliability-centered maintenance. It is a systematic approach to the delivery of business
21 objectives, including:

- 22 • Improvement of the reliability and availability of physical assets
- 23 • Minimization of risk of asset failure, downtime, and operating costs

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- Provisioning or enhancement of condition monitoring
- Enablement of predictive maintenance
- Health and Risk Models

Developing APM capabilities will provide improved visibility and targeted identification of assets that are higher risk, which can be prioritized as part of a maintenance or replacement strategy. A reduction in asset failures will reduce unplanned outages, which results in a reduction of emergent work, customer outage minutes, and associated costs. Improved visibility and analysis of health of assets also leads to more efficient deployment of power quality and energy delivery.

By proactively replacing assets prior to their anticipated failure, the Company expects to save costs on material and labor. Emergent asset replacements typically have higher costs compared to traditional replacement work as they may occur during nonbusiness hours, and the Company would not have materials staged and ready for delivery.

A comprehensive BCA is provided for the DistAM as a whole in Exhibit 152 (SAM-11), including all necessary components of AR, APM, and AIP.

It is important to note that the analysis performed in the BCA is on the full implementation of DistAM across all in-scope electric assets. The requested investment in the bridge year and test period does not include the full system costs. Future rate cases will request the needed funding to complete the full implementation of this technology.

1 **Q. Please describe the work to be accomplished in the development of the APM through**
2 **the test year.**

3 A. Company Data Scientists will design and test the necessary algorithms to produce a health
4 score with its associated risk. Depending on the type of asset and available data, a different
5 algorithm may be necessary to produce its own unique health score. As additional assets
6 are added into the AR, necessary database connections will be established to ensure the
7 correct association from the asset to its unique algorithm for processing.

8 **Q. How will assets be selected and sequenced to maximize customer benefits?**

9 A. The Company will prioritize assets following the same methodology as explained in the
10 AR section above. Prioritization will primarily be based on customer and reliability driven
11 impacts. All assets with a minimal level of data availability, even as simple as the date
12 installed, can be considered for analytics in the APM tool. Once an asset has gone through
13 the AR roll out, the Company expects to be able to optimize the health and risk assessment
14 through its QOR.

15 **Q. What is the Company's projected bridge period and test year spending level, for**
16 **which it is requesting cost recovery, for the APM investment category?**

17 A. The Company is projecting APM capital expenditures of \$770,000 in the bridge period,
18 and \$2,640,000 in the test year.

19 **Q. How will the projected expenditures support the key objectives of the Reliability**
20 **Roadmap?**

21 A. The APM tool standardizes the Company's centralized approach for managing assets. The
22 tool will directly impact reliability by improving the Company's processes around
23 calculating and visualizing asset health to ensure the most critical projects are given the

highest priority. This optimized prioritization will reduce the number of emergent failures and unplanned outages, improving reliability for customers. As described in the Reliability Roadmap, the APM aims to improve reliability through a reduction in emergent outages.

Summary

Q. Please summarize how the investments in this category support the overall electric strategy and the Reliability Roadmap.

A. DistAM directly supports the Reliability Roadmap’s objectives of reliability, system cost, and sustainability. By capturing and maintaining asset data and using it for data-driven decisions, the Company can reduce costs and improve asset reliability. As discussed in the Reliability Roadmap, data and analytics are becoming increasingly critical to inform long-term investment decisions, and to drive continuous improvement of electric distribution system operations. DistAM is an essential part of the Company’s broader initiative to maximize reliability and resiliency by optimizing how the electric distribution system is proactively maintained and managed. DistAM will enable the Company to develop and manage asset health conditions on the electric distribution system to optimize asset performance, control costs, and allow the Company to provide a more comprehensive overview of its system in future distribution plans.

In September 2024, Liberty completed their audit of the Company with a review of the Company’s Reliability Roadmap. In the Liberty Report Part II, page 87, number 26, it was concluded that “The EDIIP’s proposal for creation of DistAM comports with our recommendations about enhancing asset management.” Liberty’s conclusion that the “system appears designed to support a programmatic, analytically founded, and data driven

asset management strategy, all of which are in keeping with our recommendation.” This further supports the need for the investment described in my testimony.

VII. Planning Systems Modernization

Overview

Q. Please summarize the objectives of the Planning Systems Modernization Initiative.

A. The Planning Systems Modernization initiative is dedicated to researching, developing, and demonstrating desired future state technologies and solutions to integrate into the Company’s planning framework. This initiative takes a comprehensive and holistic view of the electric business’s planning steps and processes to assess improvement opportunities and recognize future state requirements. The goals of the Planning Systems Modernization initiative are to: leverage technological advancements to generate new or improved datasets that optimize performance of planning tools, enable new tool functionality to meet evolving business needs, specifically towards the integration of DER, and consider interdependencies with other Grid Automation initiatives to support cross-functional use cases. Currently the Planning Systems Modernization initiative is comprised of a technology upgrade to the existing Load Flow Tool necessary to maintain regulatory compliance and to conduct accurate grid modeling.

Load Flow Tool Upgrade

Q. Please summarize the objectives of the Load Flow Tool Upgrade.

A. The Load Flow Tool Upgrade seeks to modernize the Company’s planning processes and tools by developing new functionalities within and alongside the CYME power engineering software, which has been a cornerstone for utility planning departments for nearly 25 years. As discussed in the Reliability Roadmap and the below testimony, the current planning tool implementation requires an overhaul to allow the Company to meet regulatory

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1 expectations related to the fast track initial and supplemental DER review screens,
2 Michigan Transportation Electrification Plan, hosting capacity map enhancements, and the
3 increase in the Distributed Generation program cap. It will also enable the Company to
4 remain capable of proactively addressing the evolving challenges and opportunities
5 associated with increasing DER penetration and electrification on the distribution system.

6 Key components of the upgrade are expected to include, but are not limited to:

- 7 • Selection and implementation of an industry standard forecasting tool capable
8 of producing hourly, weather normalized load forecasts under alternate future
9 DER and load growth scenarios.
- 10 • Enabling time-series load flow simulations in the CYME software using
11 historical AMI, MV90, and SCADA data or the forecasted load data above.
- 12 • Leveraging CYME's Advanced Project Manager module and as-planned
13 network model to enhance collaboration, communication, and prioritization of
14 distribution system upgrades.
- 15 • CYME Gateway enhancements to automate the import of existing DER
16 interconnections into the CYME as-built network models.
- 17 • Integration with PowerClerk and/or SAP to include queued but not yet
18 commissioned DER interconnection requests in the as-planned network model.
- 19 • Integration with SAP to include detailed project scope, milestones and costs
20 into the CYME as-planned network models.
- 21 • Development of automated solutions to enable comprehensive review of the
22 fast track initial and supplemental review screens specified in R 460.946 and
23 R 460.950 of the Michigan Interconnection and Distributed Generation
24 Standards.
- 25 • Enhancements to the Company's future load and generation hosting capacity
26 maps recommended by the MPSC's September 8, 2022 Order in Case No.
27 U-20147; the Distribution System Data Access workgroup and June 30, 2023
28 Grid Integration Study filed in Case No-21251; and the March 1, 2024 Order in
29 Case No. U-21389.

30 In 2024, the Company entered a CYME Advanced Distribution Planning System
31 Discovery project to further define the scope, data requirements, technical requirements,

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high-level cost, and projected timeline of the above objectives. The final report from this effort is expected to be available by July 2025, with an optimally sequenced implementation beginning in the bridge period of the current case.

Q. What capabilities and benefits do you expect the Load Flow Tool Upgrade to provide?

A. The Load Flow Tool Upgrade will enable time-series load flow simulations in CYME. Current load modeling and allocation practices account for a single snapshot in time of peak loading conditions and cannot accurately or efficiently address the intermittent behavior of DERs and electrification. Expected benefits of integrating historical, and forecasted time-series datasets with the planning tool include:

- Significantly increased model accuracy and precision
- Reduction in model development time due to enhanced load allocation
- Proactive mitigation of voltage anomalies resulting in a reduction of customer complaints
- Expedited resolution of customer complaints when they do occur
- Visibility into the present and future time-based impacts of DER, electrification, and demand response on the distribution system under alternate scenarios for customer adoption, customer behavior, weather, etc.
- Insight into the duration and frequency of equipment overloads to determine whether deterioration and emergent failure is likely to occur, reducing the risk of overload-caused customer outages. See the LVD Overload Risk Reduction section of the Reliability Roadmap for further discussion on this topic.
- Identification of system constraints and opportunities for system optimization at any hour of the year.

Several aspects of the Load Flow Tool Upgrade are required for the Company to maintain regulatory compliance now and in the future. First, the project will enable a comprehensive review of the fast track initial and supplemental review screens specified in R 460.946 and R 460.950 of the Michigan Interconnection and Distributed Generation Standards, and will

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1 seek automation of the screens where technically feasible. It will also enable a Phase III
2 advancement of the Company's hosting capacity maps as described in the Reliability
3 Roadmap.

4 The Load Flow Tool Upgrade project is also required to complete the various
5 distribution system impact analysis and data reporting requirements of the Michigan
6 Transportation Electrification Plan, and will provide planning and interconnection
7 engineers with the insights needed to successfully navigate the increased Distributed
8 Generation program cap that was implemented by PA 235. Through the inclusion of
9 CYME's Advanced Project Manager module, the project will provide cross-departmental
10 visibility of distribution system enhancements being evaluated by LVD Circuit Planning,
11 Substation Planning, System Protection, Metro Planning, Grid Automation and
12 Distribution System Operations in a unified, as-planned network database. This integrated
13 architecture will minimize the need for manual sharing of individual CYME studies
14 between departments and will ensure that planned infrastructure upgrades are coordinated
15 in a way that maximizes value delivered to customers.

16 **Q. What is the Company's projected bridge period and test year spending level, for**
17 **which it is requesting cost recovery, for the Load Flow Tool Upgrade investment**
18 **category?**

19 **A.** The Company is projecting Load Flow Tool capital expenditures of \$3,333,000 in the
20 bridge period, and \$3,900,000 in the test year.

1 **Q. How will the projected expenditures support the key objectives of the Reliability**
2 **Roadmap?**

3 A. The Load Flow Tool Upgrade project comprises foundational technology enhancements
4 that will support many objectives of the Reliability Roadmap. Enabling time-series
5 simulation capabilities in CYME will allow planners to evaluate the duration and frequency
6 of potential device overloads to quantify whether deterioration, and eventual emergent
7 failure, are likely to occur. See the *LVD Overload Risk Reduction* section of the Reliability
8 Roadmap for further discussion on this topic. In addition to evaluating overloads, time-
9 series power flows in planning tools will allow planners to proactively identify and mitigate
10 voltage issues before they occur.

11 The industry standard forecasting tool introduced and integrated with CYME
12 through the Load Flow Tool Upgrade will make planning for alternate future customer
13 adoption, load growth, and weather scenarios a regular and defensible part of the annual
14 planning process as discussed in the Reliability Roadmap.

15 In addition to the above, the Load Flow Tool Upgrade seeks to advance the
16 accuracy, granularity, and frequency of updates to the Company's hosting capacity maps.
17 The project will explore hosting capacity process automation using either EPRI DRIVE or
18 CYME's Integrative Capacity Analysis module. For further discussion, see the Hosting
19 Capacity Section in the Reliability Roadmap.

VIII. Operational Systems Modernization

Overview

Q. Please summarize the objectives of the Operational Systems Modernization Initiative.

A. Operational Systems Modernization is a Grid Automation initiative tasked with researching, developing, and demonstrating desired technologies to improve the Company's operational response for customers. The goals of the Operational Systems Modernization initiative are to:

- Leverage technologies to generate new operational capabilities;
- Enhance operational procedures to optimize the outage restoration process;
- Enable new grid functionality to meet future state business needs; and
- Consider interdependencies with other Grid Automation initiatives to support cross-functional use cases.

The Operational Systems Modernization initiative contains the implementation of a modern FLISR program and stakeholder engagement on DER Optimization.

Q. Please explain how the capital expenditures will be allocated across this investment category in the bridge period and the test year.

A. The Company is projecting capital expenditures in the bridge period and test year for each investment category as identified in Figure 10 below.

FIGURE 10
OPERATIONAL SYSTEMS MODERNIZATION CAPITAL EXPENDITURES (\$000)

Operational Systems Modernization Investment Category	Bridge Period (Jan '25 - Mar '26)	Test Year (May '26 - Apr '27)
FLISR	2,300	2,900
Total	2,300	2,900

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Fault Location Isolation and Service Restoration

Q. Please summarize the objectives of FLISR.

A. FLISR is an ADMS application that uses communicating grid equipment, such as line sensors and reclosers, to quickly detect and locate where faults are on the system, then automatically re-route power, isolating issues to minimize the number of customers impacted. FLISR will consist of three key components: software enablement within the ADMS, hardware deployment, and process updates. This project will include the integration of electric distribution system data as well as the testing and validation of the application solution capability. An important final piece of the implementation includes the creation and modification of operating procedures to ensure safe and efficient procedures are trained and used with co-workers.

Q. What work was completed in 2024 to support FLISR?

A. In 2024, the Company launched a stakeholder team to plan and prepare for the beginning of its 2025 FLISR implementation. The Company partnered with EPRI to develop a set of detailed design documents specifying all technical aspects of a FLISR solution. EPRI evaluated the Company's existing infrastructure, processes, and technology to create a specific roadmap leading toward the implementation of FLISR, as detailed in Exhibit A-153 (SAM-12). The Company communicated with other utilities currently using an operational FLISR application to understand and apply industry-proven best practices and methods.

Q. What work will be completed in 2025 to support FLISR?

A. Following the guidance of the EPRI roadmap, the Company in 2025 will begin needed software updates within its ADMS platform, begin the process of designing networks for the initial implementation, and develop standards throughout the organization to support

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1 the deployment. The Company will continue developing its current FLISR product within
2 ADMS to support the networks planned for installation. The further development of the
3 application will enable the networks to automatically identify faults and provide solutions
4 for available restoration opportunities. The FLISR algorithm will also be tested to ensure
5 it accurately analyzes faults and avoids post-load transfer conditions that would result in
6 overloaded equipment or customer voltage deviations. This testing is critical to ensure
7 customers are not impacted by any anomalies that could arise from complex switching
8 schemes. While the Company has the base software platform of FLISR in its ADMS, there
9 are multiple applications within ADMS that the software is highly dependent upon. These
10 necessary applications will need to be further developed and will require model
11 maintenance to support a functional FLISR application. Distribution Power Flow (“DPF”)
12 and Spectra Insight, for example, are two applications within ADMS that perform iterative
13 power flow calculations and perform violation processing respectively on the real-time
14 model. Both applications will require hours of modeling and data validation, per feeder, to
15 successfully support the FLISR application and evaluate the real time state of the
16 distribution grid. The Company will be upgrading a portion of its ADMS platform to a new
17 version to support improved functionality. To accompany the software, FLISR networks
18 will be designed in 2025 using ATRs. ATRs, which the Company has installed throughout
19 the state, will be used as the primary switching device in FLISR networks. The Company
20 also plans to deploy new communication switching equipment on future FLISR networks
21 to provide new capability for isolation opportunities, further limiting the impact of an
22 outage to customers. This equipment is expected to include modern reclosers, as described

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1 in the DCM section above, as well as new device types such as cutout-mounted reclosers
2 and remote switches.

3 In 2025, the Company will evaluate the standards, processes, and procedures that
4 will require updating due to the FLISR implementation. The work done in 2025 will pave
5 the way for the further deployment of FLISR into 2026, and a longer-term rollout in
6 subsequent years. In summary, the funding request in the bridge and test periods will allow
7 the necessary updates to the DPF and SpectraInsight applications, update processes,
8 procedures, and standards, and to install ATRs as the primary switching device thus
9 establishing a network. Additional equipment such as cutout-mounted reclosers and remote
10 switches will be evaluated to increase the number of opportunities to isolate an outage and
11 limit the impact to customers.

12 **Q. What capabilities and benefits do you expect FLISR to provide?**

13 A. A FLISR system is designed to provide multiple critical capabilities including fault
14 detection, fault location prediction, fault isolation, and service restoration. It does this by
15 analyzing data from reclosers, line sensors, and other remotely communicating devices that
16 are overlaid on an electronic map within ADMS. The FLISR application is controlled
17 through ADMS's central logic. This centralized logic provides next generation switching
18 automation through FLISR by analyzing the real time operating model and the telemetered
19 devices that exist within it, to provide automatic switching solutions.

20 These switching solutions are analyzed through FLISR to avoid voltage deviations,
21 to protect the distribution system from potentially hazardous post-load transfer
22 configurations due to overloaded equipment, and to re-energize as many customers as
23 possible. The Company also plans to upgrade chosen existing ATR loops that use

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1 de-centralized control logic to the centralized FLISR architecture. The addition of
2 centralized logic will enable the chosen de-centralized ATR loops to remain in automation
3 year-round, mitigate loading limitations present on the loop during peak days, and increase
4 switching capabilities. A successful implementation of FLISR on a de-centralized loop can
5 then lead the way to upgrading the remaining de-centralized loops. An initial evaluation
6 shows that upgrading the Company's eight most limited ATR loops from de-centralized
7 logic to centralized logic that allows these extremely limited loops to remain in automation
8 nearly year-round, avoids an estimated annual 330,000 CMI. This results in an estimated
9 1,713 customer outages avoided annually. FLISR also has the intelligence to determine
10 what switching equipment can be opened and or closed to isolate an impacted area of the
11 electric distribution system so that outages are constrained to a minimal portion of the
12 system. These switching solutions can be performed remotely, reducing field switching
13 time. A 2016 report by the DOE, titled *Distribution Automation: Results from the Smart*
14 *Grid Investment Grant Program*, analyzed the benefits seen at various utilities after
15 investing \$7.9 billion in distribution automation technologies through a Smart Grid
16 Investment Grant. The report states that per outage event, FLISR operations reduced the
17 number of customers interrupted by 55% and reduced customer minutes of interruption by
18 53%.⁴ The report elaborates that "Precise fault location enabled operators to dispatch
19 repair crews accurately and notify customers of outage status, which reduced outage length
20 and repair costs, reduced the burden on customers to report outages, and increased
21 customer satisfaction."⁵ As shown in Exhibit A-154 (SAM-13), the Company estimates
22 that per FLISR network, 550,000 CMI will be avoided annually—this translates to an

⁴ See footnote 1.

⁵ See footnote 1.

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1 estimated 2,750 customer outages avoided per year per network. As the Company expands
2 into a statewide rollout, there will be many FLISR networks across the electric grid.

3 Another benefit of the program is its impact on safety. FLISR provides automatic
4 isolation of faulted zones, which in turn decreases the safety risk of the public contacting
5 energized downed wires. Since FLISR devices are telemetered, potentially downed wires
6 can be automatically secured during blue sky days and storms. This saves field resources
7 from traveling to the faulted location to manually secure downed wires and increases
8 resource availability to focus on unsecured downed wires at non-telemetered locations. An
9 increase in available field resources to attend unsecured downed wires results in greater
10 relief support to non-utility employees guarding, such as public service officials. This
11 directly supports MPSC Rule R 460.723 within the Service Quality and Reliability
12 Standards for Electric Distribution Systems.

13 **Q. How are FLISR networks selected and prioritized to maximize customer benefit?**

14 A. FLISR networks will be selected based on historical reliability and potential for operability.
15 Circuits with historically low reliability scores, specifically due to a high frequency of main
16 line faults, will be prioritized to maximize benefit. In addition to selecting circuits based
17 on low reliability, the Company will analyze options based on customer counts,
18 sectionalizing capability, and the number of adjacent circuit tie devices. Neighboring
19 circuits located in dense urban areas often provide a greater potential for load transfer
20 capability and typically serve higher customer counts. Coupling this opportunity with a
21 historically low reliability metric allows the Company to strategically select where to
22 implement FLISR.

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1 **Q. What is the Company's projected bridge period and test year spending level, for**
2 **which it is requesting cost recovery, for the FLISR investment category?**

3 A. The Company is projecting FLISR capital expenditures of \$2,300,000 in the bridge period,
4 and \$2,900,000 in the test year. It is important to note the requested investment in the bridge
5 and test period is not for a full system-wide deployment, but only the initial implementation
6 of this technology. Figure 11 provides additional details

FIGURE 11
ITEMIZED FLISR CAPITAL EXPENDITURES (\$000)

FLISR Investment Category	Bridge Period (Jan '25 - Mar '26)	Test Year (May '26 - Apr '27)
Distribution Management System enhancements	\$660	
Application Evaluations & Test Environment Simulations	\$200	
Reclosers (11) for FLISR network	\$612	\$612
Network installation	\$828	\$2,288
Total	\$2,300	\$2,900

7 **Q. How will the projected expenditures support the key objectives of the Reliability**
8 **Roadmap?**

9 A. The Company expects FLISR to be a flagship program that establishes a path to a more
10 reliable electric distribution system. FLISR is poised to improve the management of
11 electric outages by minimizing their impact and duration to customers. As described in the
12 Reliability Roadmap, this project will automatically re-route power to limit the impact of
13 outages. FLISR will both shorten outages through quicker fault detection and location, as
14 well as eliminate outages by isolating issues to the smallest area possible.

DER Optimization

Q. Please summarize the objectives of the DER Optimization Initiative.

A. DER Optimization seeks to develop a standardized methodology for delivering important capabilities, including but not limited to the modeling, monitoring, operating, and coordinating needed to optimize and safely integrate DER into the electric distribution system. This approach includes research, planning, and development of hardware and software projects to evaluate DER management capabilities across the spectrum of DER types through the implementation of a DER Management System (“DERMS”). The Company defines DERMS as an enterprise scale software platform that is located at the utility’s operational center. While broader applications such as edge DERMS and fleet DERMS are not explicitly included in this definition, it is important to note that they will be considered in the scope of the DER Optimization program.

Q. How is the Company planning to proceed with the DER Optimization initiative?

A. In Case No. U-21585, the Company agreed to form and lead a workgroup open to interested stakeholders from outside the utility to collect feedback that may influence the Company’s future DER Optimization strategy and business case. The Company will also continue to actively participate in EPRI’s DER Integration program and will explore additional opportunities to engage in DERMS-related working groups to both maintain and increase awareness of emerging best practices for DERMS implementations and valuing the benefits of DERs in other states. The Company intends to onboard a consultant to facilitate the workgroup and support the inclusion of key findings from all the above into a formalized business case that includes a comprehensive BCA and an analysis of Virtual Power Plants. This effort will inform investment requests in future cases.

1 **Q. What is the Company's projected bridge period and test year spending level, for**
2 **which it is requesting cost recovery, for the DER Optimization investment category?**

3 A. The Company is not requesting funding in this case. Instead, the Company will work to
4 establish a workgroup with the aim to bring stakeholders together to address the items
5 raised in Case No. U-21585. The Company will continue to participate in the MPSC Staff
6 workgroup on this topic.

7 **Summary**

8 **Q. Please summarize how the investments in this category support the overall electric**
9 **strategy and the Reliability Roadmap.**

10 A. The FLISR program, once fully operational, will emerge as a cornerstone of the Company's
11 overarching reliability strategy. FLISR is an industry proven approach for minimizing the
12 impact and duration of outages on the electric distribution system. By bolstering the
13 electric distribution system's capability for isolation, the FLISR program will substantially
14 reduce the number of customers affected by outages. Additionally, added visibility through
15 line sensors and other communicating devices will support reduced outage durations by
16 gaining the ability to dispatch crews directly to the area of need.

17 As stated in the Reliability Roadmap, FLISR is a significant piece of the Grid
18 Automation workplan.

19 **IX. Weather Stations**

20 **Overview**

21 **Q. Please summarize the objectives of Company-owned Weather Stations.**

22 A. In 2024, the Company hired an internal Meteorologist to conduct specific analysis on
23 weather systems that impact the Company's grid. As noted in the Liberty Report Part II,

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on page 94, there is a need to not only track weather conditions but to analyze historical trends that may adjust Consumers Energy's asset management strategy. The Company Meteorologist reviewed existing practices and concluded that there are large gaps of weather data throughout the service area due to the limited number of National Weather Service stations in Michigan. The data gathered from these additional weather stations will be used to:

- Inform storm preparation activities to speed up outage restoration by positioning resources;
- Analyze historical trends looking for a connection between various weather systems and the resiliency of the assets; and
- Feed data into the Company's outage prediction modeling to provide improved accuracy as supported by Company witness Andrew R. Snider.

Q. What type of data will be captured by these Weather Stations?

A. The Company has conducted a Request for Information across five weather station vendors. Key data to be collected includes temperature, wind speed, wind direction, barometric pressure, humidity, solar radiation, rainfall, fuel temperature, fuel moisture, and soil moisture. This data will be available for advanced analytics across many areas in the Company.

Q. How many weather stations are being proposed across the service territory?

A. The Company plans to install up to five weather stations as an initial implementation in this case, then add 25 weather stations in 2026, and an additional 70 weather stations in 2027. The total number of weather stations is expected to be 100 by 2027.

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1 **Q. Describe the analysis used to determine the total number of needed weather stations.**

2 A. A 2018 report by EPRI⁶, titled *Determining the Optimal Locations for Weather Sensors in*
3 *a Mesonet*, stated the optimal-level grid network for the Company's type of topography is
4 roughly 15 km (9.32 miles) in between sites. The Company has proposed installing weather
5 stations 16 km (10 miles) in between sites, which is a slightly greater distance than the
6 ideal grid network. That is equivalent to one weather station per 100 square miles. To
7 complete the 10-mile by 10-mile grid resolution within the Company's more than 28,000
8 square mile service territory, Consumers Energy would need to install 100
9 Company-owned weather stations. This grid resolution includes the already installed
10 National Weather Service weather stations. While the National Weather Service provides
11 access to weather stations, large gaps remain around the state. The largest gaps in weather
12 station data occur in Northeast Michigan. The average county land size in Northeast
13 Michigan is 560 square miles, where the average county only has one to two weather
14 stations monitoring wind. Worse yet, there are currently zero weather stations within the
15 entirety of Gladwin County that monitor wind speed and wind direction.

16 **Q. What benefits do you expect these Weather Stations to provide?**

17 A. To prepare for severe weather, the Company employs the prestaging of line workers close
18 to where the greatest impact is expected. These weather stations will provide real-time
19 weather data signaling the most optimal placement of resources as a system is progressing
20 across the state. Acting on this improved situational awareness enables faster restoration

⁶ *Determining the Optimal Locations for Weather Sensors in a Mesonet*. EPRI, Palo Alto, CA: 2018. 3002007610.
<https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&cad=rja&uact=8&ved=2ahUKEwjQt82vyZSNAxWA4MkDHT-SOcgQFnoECCUQAQ&url=https%3A%2F%2Frestservice.epri.com%2Fpublicdownload%2F000000003002007610%2F0%2FProduct&usg=AOvVaw283Pq0-tgIqWG5IgGeYdyr&opi=89978449>

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1 times for customers. Reducing the duration of a storm not only helps the Company meet
2 the MPSC Service Quality and Reliability Standards, but it can also avoid service
3 restoration costs. As shown in Exhibit A-155 (SAM-14), the Company estimates avoided
4 CMI of 12,575,250 from 2025 through 2036. Beyond the operational benefits, additional
5 analytics will be performed to determine asset resilience and performance. The observed
6 weather conditions will provide the Company insight to improve equipment, material, and
7 engineering standards.

8 Increased weather data will also be used in the Company's developing AI outage
9 prediction model as discussed by Company witness Snider. The more data the outage
10 model has, the more accurate it can be. A study was published through EPRI, titled *Case*
11 *Study: Demonstration of the Quantum Weather Storm-Prediction Model and Application*,⁷
12 concluding that an increase in spatial and temporal resolution increased the accuracy of
13 forecast models.

14 **Q. What benchmarking was performed to support this investment?**

15 A. Weather stations can provide valuable information around complex forecasting
16 topography. Central Hudson Gas and Electric took part in the 2018 EPRI study,
17 determining the optimal number of weather stations to maintain in their grid. Utilities
18 across the United States have been able to increase their situational awareness for wildfire
19 risk mitigation by installing weather stations across their electric grid. Portland General
20 Electric ("PGE"), for example, has a network of more than 80 weather stations that provide
21 detailed weather data, as well as AI-enhanced cameras that assist with fire detection and
22 awareness. In addition, San Diego Gas and Electric ("SDG&E") currently has more than

⁷ *Case Study: Demonstration of the Quantum Weather Storm-Prediction Model and Application*. EPRI, Palo Alto, CA: 2016. 3002004268.

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220 weather stations within a 4,000 square mile service territory While wildfire detection is a growing space for many weather station vendors, the Company remains focused on improved outage response when storms impact customers.

Q. Please explain how the capital expenditures will be allocated across this investment category in the bridge period and test year.

A. The Company is projecting capital expenditures in the bridge period and test year for each investment category as identified in Figure 12 below.

Figure 12
WEATHER STATIONS EXPENDITURE SUMMARY (\$000)

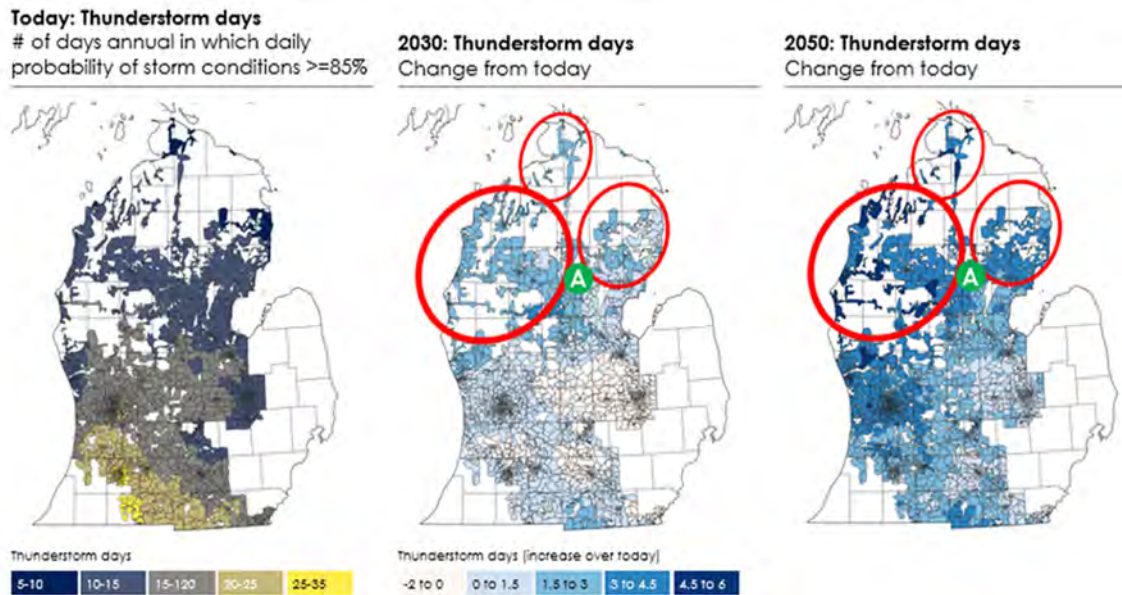
	Bridge Period (Jan '25 - Apr '26)	Test Year (May '26 - Apr '27)
Weather Stations	71	362

Q. How will the projected expenditures support the key objectives of the Reliability Roadmap?

A. The decision to add weather stations to the electric grid was primarily made as a result of the Reliability Roadmap's identification of the risk of increasingly severe weather resulting from climate change. As seen in the Reliability Roadmap, the Company has experienced repeated instances of strong winds causing large-scale outages and a general increase in Major Event Days per year. The number of days with thunderstorms in the state of Michigan is anticipated to increase through 2050, as described in the Reliability Roadmap. See Figure 13 below.

FIGURE 13

2030 AND 2050 THUNDERSTORMS INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY

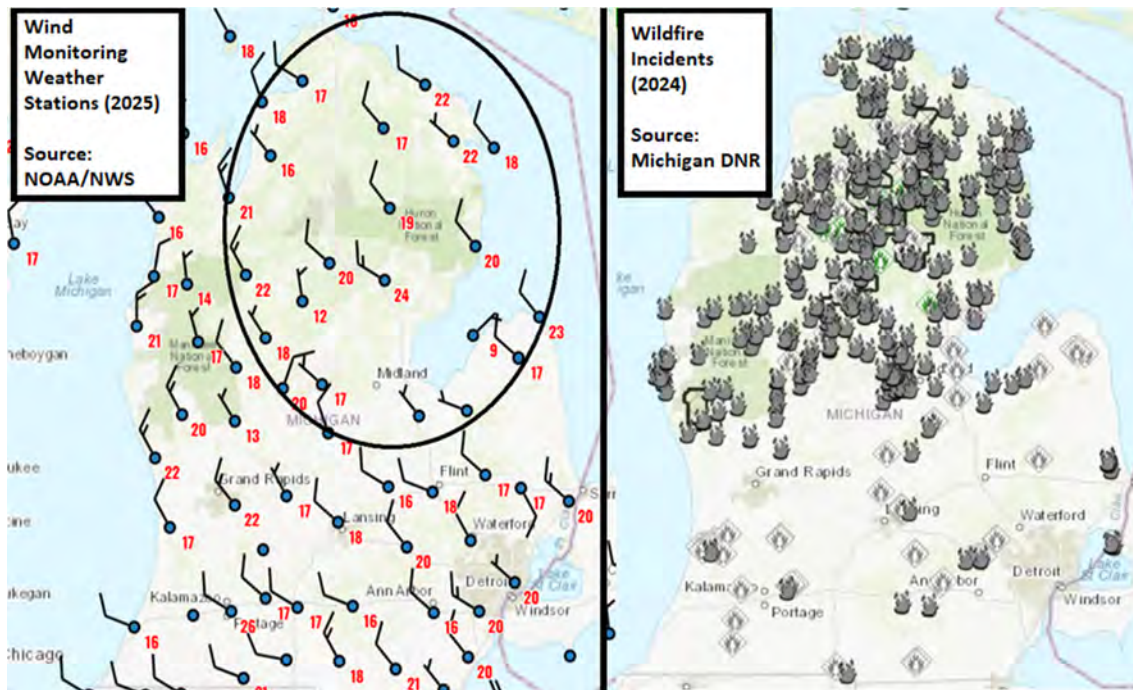


The greatest potential for an increase in thunderstorm days is in Northeast Michigan, where the least amount of weather data is available and where the fewest weather stations currently exist. Thunderstorms pose wind and lightning concerns, which correlate to potential outages and wildfire initiation risk.

Northeast Michigan additionally holds the highest wildfire risk zone within the Company's service territory. Figure 14 below compares the current National Weather Service wind monitoring weather stations with the wildfire incidents that occurred in 2024. Currently, the region with the highest wildfire risk in Michigan is correlated with the least amount of weather station data.

FIGURE 14

COMPARISON OF WIND MONITORING WEATHER STATIONS TO WILDFIRE INCIDENTS



1 There are currently 26 wind-monitoring National Weather Service weather stations in the
2 Company's Northeast electric service territory, covering nearly 6,800 square miles. Based
3 on the ideal 10-mile by 10-mile grid spacing between weather stations, Northeast Michigan
4 should have at least 68 weather stations covering that region. The Company plans to install
5 44 of the proposed 100 weather stations in Northeast Michigan to increase situational
6 awareness.

7 The Liberty Report Part II, pages 112-113, conclusion 6, determined more needs to
8 be done to improve outage modeling. This additional weather data will be incorporated
9 into the Company's modeling and used to make operational decisions that limit the impact
10 of outages to customers.

SCOTT A. MCPHAIL II
U-21870 DIRECT TESTIMONY

1 **Q. Please provide an example event when additional weather stations could have been**
2 **beneficial to the Company and customers.**

3 A. Michigan experienced a historic weather event in late March 2025, resulting in widespread
4 accumulating ice in Northern Michigan and 14 confirmed tornadoes in Michigan. The ice
5 accumulation in Northern Michigan was only comparable to an ice storm that occurred in
6 February 1922, making it the worst ice storm to strike Northern Michigan in over 100 years.
7 That storm led to the Governor declaring a state emergency for 10 counties in Northern
8 Michigan.

9 Forecasting freezing rain and ice is one of the most challenging jobs for a
10 meteorologist. Whether the precipitation lands on the surface as snow, rain, freezing rain,
11 or sleet comes down to a few degrees in temperature. As previously mentioned, Northeast
12 Michigan consists of the fewest weather stations in the state. The proposed weather stations
13 could have provided the Company greater situational awareness around the exact type of
14 precipitation that was accumulating based on the exact surface temperature.

15 The same storm system produced widespread damaging wind gusts and tornadoes
16 in Southern Michigan. One of the already installed National Weather Service weather
17 stations recorded a 96-mph wind gust in Jackson. That wind report provided a quick
18 response to nearby crews to travel to Jackson before the outage was officially reported in
19 the Company's system. Wind gusts are sporadic and inconsistent in nature. A wind gust
20 report can vary greatly by a matter of miles. A greater number of operational weather
21 stations within the Company's electric grid provides a greater opportunity for the Company
22 to respond quickly to observed weather conditions.

X. Summary

Q. Please provide a summary of your testimony and the intent of investing in Grid Automation to support the Company's electric distribution system.

A. My testimony provided an overview of the Company's efforts to establish an automated and modernized electric grid. Grid Automation projects were shown to have provided benefits to customers through better reliability and cost control. The Company has a track record of proven successes as seen through the delivery of the ADMS, ATR Loop Schemes, CVR, and other programs that have become a normal part of running the business. Grid Automation investments have been shown to support the key objectives of the Reliability Roadmap and play a key role in building the grid of the future, as the Company installs new technology with proven capabilities on the electric distribution system.

Q. Please summarize the Grid Automation capital expenditure plan in this filing.

A. The Grid Automation capital expenditure plan outlined in this testimony is summarized in Figure 15 below, and as shown in Exhibit A-113 (MPK-3) line 14, columns (k) and (l). Dollars shown are in thousands.

Figure 15
GRID AUTOMATION EXPENDITURE SUMMARY (\$000)

	Bridge Period (Jan '25 - Apr '26)	Test Year (May '26 - Apr '27)
Grid Automation	25,691	17,837

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

ASHLEY E. MESCHKE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

ASHLEY E. MESCHKE
U-21870 DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

2 A. My name is Ashley Meschke, and my work address is One Energy Plaza, Jackson, MI
3 49201.

4 **Q. By whom are you employed and what is your present position?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
6 as the Director of Lean Strategy.

7 **Q. Please review your educational and business experience.**

8 A. I hold a bachelor’s degree in Criminal Justice with a specialization in Security Management
9 from Michigan State University, and a master's in Infrastructure Planning and Management
10 from The University of Washington. I joined Consumers Energy in 2012, and for the last
11 eight years of my career I have worked with different areas of the Company to improve
12 metrics using lean methodologies including gas, electric, and customer. For the last six
13 years, I have been accountable for leading teams dedicated to driving performance
14 improvement and achieving targets associated with the Employee Incentive Compensation
15 Plan (“EICP”) operational goals.

16 **Q. What are your responsibilities as Director of Lean Strategy?**

17 A. In the Director of Lean Strategy role, I am responsible for the development, governance,
18 and administration of the EICP operational goals. This includes but is not limited to the
19 development of annual goals and associated targets, facilitating the development of plans
20 to support goal achievement, ensuring the Company’s lean operating system is leveraged
21 to manage performance at various levels of the organization, and ensuring internal
22 reporting standards are met.

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1 **Q. Have you previously testified before the Michigan Public Service Commission**
2 **(“MPSC” or the “Commission”)?**

3 A. Yes, I have testified in Case Number U-21806, the Company’s Gas Rate Case currently
4 pending before the Commission.

5 **Q. What is the purpose of your direct testimony in this proceeding?**

6 A. The purpose is to provide support for Consumers Energy’s request for rate recovery for the
7 test year employee compensation costs related to the EICP operational goals. Specifically,
8 I will outline the operational goals included in Consumers Energy’s EICP and how they
9 provide customer-related benefits.

10 **Q. Are you sponsoring any exhibits?**

11 A. Yes, I am sponsoring the following exhibits:

12 Exhibit A-156 (AEM-1) 2024-2025 EICP Operational Goals;

13 Exhibit A-157 (AEM-2) 2024 Customer Benefits: Employee Safety;

14 Exhibit A-158 (AEM-3) 2024 Customer Benefits: Reliability; and

15 Exhibit A-159 (AEM-4) 2024 Customer Benefits: Culture Index – Reduced
16 Employee Turnover.

17 **Q. Please explain the process for establishing the Company’s EICP goals.**

18 A. Each year, the Company identifies key operational and financial goals to focus on for the
19 next year. The EICP operational goals are established by analyzing progress on the
20 Company’s strategic initiatives and developing key performance indicators that focus on
21 driving performance improvement. The Company establishes operational goals grounded
22 in delivering customer value through safe, reliable, affordable, clean energy service across
23 the business. Operational goals are intended to be cross-functional and apply to all eligible
24 employees to incentivize goal achievement through daily continuous improvement and

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1 application of our Lean operating system, The CE Way. Operational goals are developed
2 in partnership with the Company's leadership team and are approved annually by the Board
3 of Directors. The process for developing annual targets is outlined later in my testimony.

4 **Q. What operational goals will make up the 2025 EICP portfolio?**

5 A. The EICP operational goals for 2025 include Employee Safety, Culture Index, Customer
6 Experience Index, Electric Reliability, Waste Elimination, and Methane Emission
7 Reduction. As outlined in Company witness Amy M. Conrad's testimony, the Company is
8 not seeking recovery for Waste Elimination due to the financial nature of the operational
9 goal. As outlined in Exhibit A-71 (AMC-1), operational goals have not changed from the
10 2024 to 2025 plan year; however, targets have changed to drive continuous improvement.

11 **Q. Please explain the Employee Safety goal.**

12 A. The Employee Safety goal is composed of three components: (1) Recordable Incident Rate
13 (2) High Risk Injuries (3) Fatalities. The Recordable Incident Rate accounts for 30% of the
14 metric and is measured using the Occupational Safety and Health Administration
15 ("OSHA") industry standard. High-Risk Injuries account for 70% of the metric and include
16 both OSHA recordable and non-recordable incidents with the potential for resulting in a
17 severe injury or fatality. The Edison Electric Institute's ("EEI") Safety Classification
18 Learning Model is leveraged as the industry standard for reporting and High-Energy
19 Serious Injury or Fatality ("HSIF") and Potential Serious Injury or Fatality ("PSIF") are
20 included. If there is a fatality, there is a 0% payout for the Employee Safety operational
21 goal in its entirety. Please refer to A-157 (AEM-2) for additional information on the
22 calculation method.

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1 **Q. Why is the Employee Safety goal included in the EICP?**

2 A. Employee Safety is foundational to the success of the Company. Creating and maintaining
3 a safe workplace and culture shows the Company's commitment to its coworker's
4 wellbeing and their ability to go home safely every day.

5 When employees work safely it translates to delivering safe, reliable, affordable, and clean
6 energy services to customers—while completing the work more efficiently, and avoiding
7 costs associated with injuries. Customer benefits associated with Employee Safety are
8 outlined later in my testimony.

9 **Q. Please explain the Culture Index goal.**

10 A. The Company uses an all-employee survey to determine the Culture Index, which is made
11 up of three indices: (1) Engagement; (2) Empowerment; and (3) Diversity, Equity, and
12 Inclusion. The indices are measured leveraging industry standards established by Korn
13 Ferry, and data is collected leveraging the Qualtrics survey platform. Each of the three
14 indices are derived by averaging the favorability score from employee responses.
15 Additional information on the calculation method is outlined in Exhibit A-156 (AEM-1).

16 **Q. Why is the Culture Index goal included in the EICP?**

17 A. The Culture Index goal aims to enhance employee experience and engagement. Gallup's
18 meta-analysis shows that companies with high employee engagement have 10% higher
19 customer loyalty and engagement, 14% higher productivity, 43% less turnover, and 18%
20 less absenteeism compared to those with low engagement¹. Benchmark data indicates that
21 peer utilities have a turnover rate of 7.3%, while the Company's four-year historical
22 average is 2.4%. Gallup estimates turnover costs at 1.5-2.0 times the employee's salary. By

¹ <https://www.gallup.com/workplace/285674/improve-employee-engagement-workplace.aspx%23ite-285704>

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maintaining a 2% competitive advantage over peers and using a 1.5 multiplier as the conservative end of Gallup's estimate, the Company avoids at least \$7,064,260 in annual turnover costs. Exhibit A-159 (AEM-4) shows the calculation in further detail.

Q. Please explain the Customer Experience Index goal.

A. The Customer Experience Index is an industry standard developed and administered by Forrester² to measure the quality 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 focuses on the following experiences: (1) Billing and Payment, (2) Outage, (3) Moving, (4) Field, and (5) Other across the following channels: (1) Digital (website and mobile application), (2) Live agent, and (3) the Interactive Voice Response ("IVR"). Please refer to A-156 (AEM-1) for additional information on the calculation method.

Q. Why is the Customer Experience Index goal included in EICP?

A. The Customer Experience Index goal focuses on ensuring 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 Electric Reliability goal is measured using the System Average Interruption Duration Index ("SAIDI") as the industry standard to measure and improve performance. SAIDI has two components for measuring and reporting reliability as follows:

² <https://www.forrester.com/research/>

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(1) The System Average Interruption Frequency Index (“SAIFI”) – this indicates the frequency of outages that occur due to system condition, configuration, and related external conditions (e.g. weather patterns, forecasts, etc.)

(2) The Customer Average Interruption Duration Index (“CAIDI”) – this indicates how long interruptions last due to system conditions, resources available, number of interruptions, and storm restoration activities.

SAIDI results are calculated by multiplying SAIFI and CAIDI. SAIDI is calculated excluding Major Event Days (“MEDs”) to normalize performance data for unusually severe weather.

Q. Why is the Electric Reliability goal included in EICP?

A. Benchmarking and internal data indicate that reliability is one of the top drivers for overall customer satisfaction, and the Company is committed to providing safe, reliable, and affordable electric service. The Electric Reliability goal is directly aligned with the Company’s Electric Reliability Roadmap³ (i.e., Electric Distribution Infrastructure Investment Plan) and will position the Company for future success as electric demand increases. Improving electric reliability also provides an economic benefit to customers and is discussed later in my testimony.

Q. Please explain the Methane Emissions Reduction goal.

A. The Methane Emissions Reduction goal aims to reduce fugitive methane emissions associated with the Company’s natural gas system.

Reductions are achieved through the following work activities:

(1) Retiring and replacing miles of natural gas distribution mains;

³ <https://www.consumersenergy.com/-/media/CE/Documents/company/electric-generation/ediip-report.pdf>

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- 1 (2) Retiring and replacing natural gas distribution services (both vintage and non-
- 2 vintage materials);
- 3 (3) Completing natural gas distribution system leak replacements;
- 4 (4) Performing well plug and abandonment activities; and
- 5 (5) reducing compression venting.

6 Reductions are measured in metric tons, leveraging the emission factors outlined in the

7 Environmental Protection Agency's Greenhouse Gas Reporting Rule, 40 CFR Part 98

8 Subpart W.

9 **Q. Why is the Methane Emission Reduction goal included in EICP?**

10 A. In 2020, Michigan's Governor signed an executive order creating the Michigan Healthy

11 Climate Plan, which outlines goals for Michigan to achieve economy-wide carbon

12 neutrality no later than 2050, and to maintain net negative greenhouse gas emissions

13 thereafter. The executive order aims for a 28% reduction below 2005 levels of greenhouse

14 gas emissions by 2025⁴. The federal government has established goals to reduce

15 greenhouse gas emissions by 50-52% by 2030 and achieve net-zero emissions by 2050⁵.

16 The EICP Methane Emissions goal is directly in support of state and federal goals and

17 aligns with the Company's Natural Gas Delivery Plan that is founded on the Company's

18 commitment to providing safe, reliable, affordable, and increasingly clean natural gas for

19 Michigan, and outlines the goal to achieve net-zero methane emissions by 2030.

⁴ <https://www.michigan.gov/whitmer/news/state-orders-and-directives/2020/09/23/executive-directive-2020-10>

⁵ <https://www.energy.gov/topics/net-zero-economy>

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U-21870 DIRECT TESTIMONY

1 **Q. Please explain the annual target setting process.**

2 A. Targets for the EICP operational goals are proposed by subject matter experts, leveraging
3 industry benchmarking, best practices, long-term strategies, annual work plans, and
4 historical performance data. These targets are then recommended to the Company's officer
5 team to validate that targets are both challenging and achievable and will result in the
6 delivery of customer value. The officers present recommendations to the Board of
7 Directors for final approval.

8 **Q. Has the Company quantified customer benefits that are tied to EICP?**

9 A. Yes. Although specific quantification of the benefits is not easy to perform for every
10 metric, the Company has evaluated direct quantitative benefits of customers for three key
11 operational goals: Employee Safety, Electric Reliability, and Culture Index. The Company
12 has assessed indirect and/or qualitative benefits associated with the other goals.

13 **Q. Is there a direct tie between the design of the EICP operational goals and desirable**
14 **benefits for customers?**

15 A. Yes. There is a direct tie between the design of the EICP operational goals and desirable
16 benefits for customers.

17 The operational goals focus on delivering customer value through safe, reliable, affordable,
18 and clean energy services—all desirable benefits for customers.

19 **Q. Do you believe that benefits to customers from the EICP goals will, at a minimum, be**
20 **commensurate with the programs' costs?**

21 A. Yes. Company witness Conrad and I present evidence in support of including EICP costs
22 at the 100% payout level, proving that including these costs will not result in excessive
23 rates, and the costs of the EICP will, at a minimum, be commensurate with the programs'

ASHLEY E. MESCHKE
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costs. Company witness Conrad discusses various benefits to customers from the design of the Company's EICP. In addition, there are both quantitative and qualitative benefits to the successful achievement of these goals. The design of the EICP clearly leads to lower costs and improved service which benefit customers.

Q. How have you evaluated the EICP goals' direct quantitative benefits?

A. The direct quantitative benefits associated with Employee Safety, Electric Reliability, and Culture Index have been calculated. For each of these metrics the Company uses a four-year historical average baseline. The first of those metrics is Employee Safety. The Employee Safety goal for 2025, when met, will reduce incidents by 34% from the four-year historical average. The resulting reduction in lost workdays and medical expenses is \$1,278,673 of annual direct savings. Expected indirect savings, calculated using OSHA's recommended multiplier, totals \$889,864 of annual savings. Together, the projected annual direct and indirect savings that accrue to the benefit of the customer totals \$2,168,537. Exhibit A-157 (AEM-2) provides the calculation of these savings.

The second metric that can be readily translated to quantifiable cost avoidance for customers is in electric reliability. Using cost per outage minute estimates from Berkeley Labs⁶, the 8.0-minute average annual reduction in outage minutes from the four-year historical performance has resulted in annual economic benefits to customers more than \$25,115,262. Exhibit A-158 (AEM-3) provides the calculation of these savings.

Third, there are benefits related to the Culture Index created by reducing employee turnover for Company employees with <1-4 years of tenure by 2% as compared with industry peers. The average annual salary of an employee with tenure of <1-4 years of

⁶ <https://www.osti.gov/servlets/purl/963320>

ASHLEY E. MESCHKE
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1 experience is \$99,990, and lower turnover avoids costs equal to at least 1.5 times the
2 employees' annual salaries. This means that by reducing turnover in this employee group
3 by 2%, when compared to utility peers, the Company will avoid costs of \$7,064,260.
4 Exhibit A-159 (AEM-4) shows the calculation in further detail.

5 **Q. How have you evaluated the EICP goals' other qualitative benefits?**

6 A. The Methane Emission Reduction goal is essential to achieving the Company's goal of
7 net-zero methane emissions from its natural gas system by 2030, which supports the
8 Michigan Governor's goal for Michigan to achieve economy-wide net-zero greenhouse gas
9 emissions, and to be carbon neutral by 2050. The direct economic benefits for customers
10 are difficult to calculate, but the qualitative benefits are beyond dispute. Improved
11 Customer Experience is another benefit of achieving EICP goals that is difficult to quantify
12 but nonetheless quite real. The benefits of pursuing improvement in Customer Experience
13 have been discussed above.

14 **Q. Why have you included both electric and natural gas benefits in your quantification?**

15 A. Consumers Energy's utility operations are combined in one organization and operational
16 goals are established in critical areas to drive the delivery of customer value through safe,
17 reliable, affordable, and clean energy services across electric and natural gas operations.
18 The quantified benefits of Employee Safety, the Culture Index, and Electric Reliability
19 show that benefits to electric customers clearly exceed the employee incentive
20 compensation amounts that Consumers Energy has requested be included in rates in this
21 case.

1 **Q. What is the Company's reasoning for having a Methane Emission Reduction goal**
2 **attributed to electric business employees?**

3 A. The EICP goals align with Company priorities, providing targets for the entire
4 organization. Prioritizing Electric Reliability and Methane Emission Reduction is essential,
5 as previously mentioned in my testimony. The Company quantifies EICP benefits to ensure
6 electric customers pay for the benefits they receive. Given the combined operations, and
7 the majority of non-union employees supporting both electric and gas operations, it is
8 reasonable to include both Electric Reliability and Methane Emission Reduction goals in
9 the EICP.

10 **Q. What portion of the direct benefits that you have quantified above do you conclude**
11 **benefit electric customers?**

12 A. A portion of the quantified benefits in Employee Safety and the Culture Index directly
13 benefit electric customers. By allocating 60% of these combined customer benefits, the
14 Company calculates annual savings for electric customers as follows: \$1,301,122 from
15 Employee Safety, \$4,238,556 from avoided turnover costs associated with the Culture
16 Index. Additionally, the full customer benefit of \$25,115,262 from Electric Reliability
17 impacts all electric customers. This totals \$30,654,930 in value specifically for electric
18 customers, far exceeding the total costs of the EICP allocated to electric customers.

19 **Q. Why did you use a 60% allocation to evaluate benefits to electric customers?**

20 A. The 60% allocation is based on the total number of electric employees as a percentage of
21 total number of Consumers Energy employees. Using the percentage of total employees
22 is a reasonable methodology to allocate the Employee Safety and Culture Index benefits
23 identified above.

ASHLEY E. MESCHKE
U-21870 DIRECT TESTIMONY

1 **Q. Should the Company be pursuing these benefits independent of the EICP?**

2 A. Yes. The EICP takes this into consideration. As discussed by Ms. Conrad in her direct
3 testimony, incentive mechanisms help communicate priorities, engage employees in
4 business success, reward valued skills and behaviors, and create business understanding
5 for employees. The EICP is structured in a way that focuses employees on delivering
6 customer value through continuous improvement. Making it clear to employees that a
7 portion of their market-based compensation is at risk and depends upon their collective
8 ability to meet these targets emphasizes the importance of goal achievement and
9 encourages coworkers to deliver their best performance.

10 **Q. Do you believe that the EICP is the reason that the above benefits have been realized?**

11 A. Yes. I believe the design of the EICP is intended to and does make it significantly more
12 likely customer benefits will be achieved by establishing operational goals to improve the
13 Company's ability to continuously improve the delivery of customer value through safe,
14 reliable, affordable, and clean energy services. By placing a portion of employees'
15 market-based compensation at-risk, employees are incentivized to meet the EICP
16 operational goals.

17 **Q. Are you confident the Company can consistently achieve 100% targets on the EICP**
18 **operational goals?**

19 A. Yes. The four-year historical average for goal achievement illustrates that the Company
20 and its employees have consistently achieved 115% of the targets associated with the EICP
21 operational goals. Refer to Exhibit A-156 (AMC-1) for EICP Operational Performance
22 Metrics for the operational goals and targets in 2024 and 2025.

ASHLEY E. MESCHKE
U-21870 DIRECT TESTIMONY

1 **Q. Do you believe that any of the metrics included in the EICP are duplicative?**

2 A. No. The metrics have been selected to create a designed, balanced focus on safety,
3 reliability, and employee culture that results in broad customer benefits.

4 **Q. Does this conclude your direct testimony?**

5 A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

MEGAN L. METZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MEGAN L. METZ
U-21870 DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

2 A. My name is Megan L. Metz, and my business address is 1945 West Parnall Road, Jackson,
3 Michigan 49201.

4 **Q. By whom are you employed?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

6 **Q. In what capacity are you employed?**

7 A. I am the Director of Electric Supply Operations and Power Supply Cost Recovery
8 (“PSCR”) within the Electric Supply Organization.

9 **QUALIFICATIONS**

10 **Q. Please describe your educational background and business experience.**

11 A. I received a Bachelor of Science degree in Industrial and Operational Engineering from
12 University of Michigan in 2002 and a Master of Business Administration degree from
13 Spring Arbor University in 2007. I have been employed by Consumers Energy since 2002,
14 in roles primarily related to Electric Generation and with increasing levels of responsibility.
15 From 2002 to 2010, I held engineering positions in Production Cost Modeling, Fuel
16 Supply, Plant Operations, and Strategy Development. From 2010 to 2013, I was Plant
17 Compliance and Economic Analysis Director, responsible for coordinating the long-term
18 financial plan and budget for all Electric Generation, economic analysis of projects, outage
19 scheduling and environmental, health & safety and North American Reliability
20 Corporation (“NERC”) compliance. From 2013 to 2014, I was Production Engineer at the
21 J.H. Campbell 1 and 2 facility, performing outage management and operations support and
22 supervision. From 2014 to 2017, I was the Fuel Procurement Director, responsible for
23 purchasing coal and gas for Consumers Energy’s generation facilities. From 2017 to 2020,

MEGAN L. METZ
U-21870 DIRECT TESTIMONY

I was Director of Electric Regulatory Compliance, responsible for Federal Energy Regulatory Commission (“FERC”), NERC, Michigan Public Service Commission (“MPSC” or the “Commission”) Electric Code, and Midcontinent Independent System Operator, Inc. (“MISO”) regulation compliance. From 2020 to present, I have been the Director of Merchant Operations and PSCR, responsible for the Company’s Merchant Operations center which is a 24x7 control center that interfaces with MISO and manages dispatch electric generation to meet customer load. In addition, I am responsible for production cost modeling and managing the Company’s generation capacity through the MISO Planning Resource Auction (“PRA”).

Q. Have you previously provided testimony before the Commission?

A. Yes. I provided testimony in the following cases:

- MPSC Case No. U-21389, Consumers Energy 2023 Electric Rate Case;
- MPSC Case No. U-21585, Consumers Energy 2024 Electric Rate Case; and
- MPSC Case No. U-21647, Consumers Energy 2023 Demand Response Reconciliation.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is: (i) support PSCR costs expected to be incurred during the test year period beginning from May 1, 2026 and ending April 30, 2027; (ii) discuss the Company’s State Reliability Mechanism (“SRM”) capacity charge inputs, cost offsets, demand, and reconciliation; (iii) provide an update of MISO’s Seasonal Resource Adequacy Construct; (iv) support the value of continued investment in the Company’s generation assets; (v) support the value of the Company’s Demand Response (“DR”) programs; and (vi) present and support the value of upgrades to PCI Energy Solutions (“PCI”) software.

MEGAN L. METZ
U-21870 DIRECT TESTIMONY

1 **Q. How is your testimony related to the testimony of other Company witnesses?**

2 A. Company witness Eugene M. Breuring’s direct testimony ties to the PSCR costs, Large
3 Economic Development Rate (“LED”), and Long-Term Industrial Load Retention Rate
4 (“LTILRR”) revenues. Company witness Emily A. Davis discusses the SRM charge and
5 how the SRM relates to the Cost of Service. Company witness Richard T. Blumenstock
6 describes the Company’s generation asset investment plan. Company witness Alex M.
7 Gast addresses the Company’s planned spending and growth of DR programs. Company
8 witness Thomas P. Clark supports Integrated Resource Plan (“IRP”) Settlement storage
9 projects.

10 **Q. Have you prepared any exhibits in conjunction with your direct testimony?**

11 A. Yes, I am sponsoring the following exhibits:

12 Exhibit A-160 (MLM-1)	Power Supply Cost Recovery Forecast for
13	May 1, 2026 – April 30, 2027;

14 Exhibit A-161 (MLM-2)	Consumers Energy Forecast – Energy
15	Market Sales Revenue and Total Variable
16	Expense; and

17 Exhibit A-162 (MLM-3)	Summary of PPA Changes from
18	September 30, 2024 – February 1, 2025.

19 **Q. Were these exhibits prepared by you or under your supervision?**

20 A. Yes.

21 **POWER SUPPLY COST RECOVERY**

22 **Q. Please explain power supply charges applicable to the Company’s customers.**

23 A. Power supply charges are applicable to the Company’s full-service customers only.
24 Full-service customers receive power supply service, including generation and
25 transmission costs, as well as delivery service from the Company. Retail Open Access

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1 (“ROA”) customers only receive delivery service from the Company and obtain their
2 power supply service from an authorized alternative electric supplier.

3 **Q. Are the Company’s power supply costs recoverable?**

4 A. Yes. All the Company’s reasonably and prudently incurred power supply costs are
5 recoverable. Power supply costs are forecast in an annual PSCR Plan filing with the MPSC
6 and subsequently reconciled in a related annual PSCR Reconciliation filing with the
7 MPSC. Forecasting, reconciliation, and recovery of PSCR costs is governed by Michigan
8 statute, MCL 460.6j, 1939 PA 3.

9 **Q. Please explain how PSCR-related costs are included in this filing.**

10 A. PSCR costs are included in this filing as a forecast of expenses for the projected test year
11 beginning May 1, 2026 and ending April 30, 2027. PSCR expenses are recovered monthly
12 from full-service customers through a PSCR factor as described and estimated in this case
13 by Company witness Breuring. A portion of the PSCR expenses related to the cost of
14 capacity are utilized to calculate the SRM charge as discussed by Company witness Davis
15 and as discussed later in this direct testimony.

16 **Q. Please explain Exhibit A-160 (MLM-1).**

17 A. Exhibit A-160 (MLM-1) is the forecast of the Company’s generation requirements,
18 transmission expenses, and purchased and interchange expenses for the projected test year
19 ending April 30, 2027. The total system requirements represent the projected total energy
20 supply requirements, presented in MWh, to serve customer load. The total system
21 requirements are projections of energy production (or consumption) based upon generation
22 requirements from energy load forecasts, unit heat rates, maintenance schedules, unit
23 random outage rates (“RORs”), fuel costs, and unit net demonstrated capabilities. Variable

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1 expenses are a forecast based upon the projected MWh, commodity price forecasts, power
2 purchase agreement (“PPA”) variable cost provisions, and renewable energy transfer costs.
3 Total capacity and non-utility generator (“NUG”) costs are based upon the capacity
4 forecast for the Company and approved contract terms of the contracts. Also included are
5 MISO cost projections for transmission and energy markets administration, as well as
6 chemical reagent costs based upon generating unit energy production forecasts. The
7 LTILRR revenues, and the LED Rate, lines 43 and 44, respectively, of Exhibit A-160
8 (MLM-1) are shown separately such that the forecasted total power supply costs recovered
9 from the remaining full-service customers can be shown on line 45 of Exhibit A-160
10 (MLM-1). The total power supply cost levels are consistent with prior years.

11 **Q. How were the values in Exhibit A-160 (MLM-1) derived?**

12 A. The values were derived from the Aurora Production Costing Program (“Aurora”), which
13 was the same platform used in the Company’s 2021 IRP filing, Case No. U-21090. Aurora
14 is a computer software application developed by Energy Exemplar (“EE”) that supports
15 electric utility decision analysis and corporate strategic planning. Aurora simulates the
16 dispatch of the Company’s generating resources, purchased power resources, and
17 interchange power resources to meet projected customer electric demand requirements.
18 The projected customer electric demand requirements are discussed in further detail in
19 Company witness Breuring’s testimony.

20 The primary inputs to Aurora are projected system loads, unit heat rates,
21 maintenance schedules, unit RORs, fuel costs, unit net demonstrated capabilities and
22 purchased and interchange (“P&I”) power availability and costs. The model used by
23 Aurora is structured to align as closely as possible with the way that MISO operates and

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1 administers the energy market. The system load and system generation requirements data
2 were provided by Company witness Breuring. Coal, oil, and natural gas costs were
3 provided by the Company's Fossil Fuel Supply Group. Information about the Company's
4 generating units was provided by the Company's Plant Operations Group and discussed in
5 the testimony of Company witness Blumenstock.

6 The primary outputs yield a monthly cost amount for: (i) each unit of energy in the
7 system requirements; (ii) any variable expenses; (iii) capacity, fixed and purchased NUGs
8 costs; as well as (iv) power supply costs, value of delivered energy, total expenses, and any
9 revenue credits. This model is also used to develop the Company's presentation in its
10 annual PSCR Plan cases.

11 **Q. What expenses are included in the PSCR forecast?**

12 A. PSCR expenses include both fixed and variable expenses. Variable expenses include, but
13 are not limited to, fuel expense, variable purchased energy, and MISO interchange, as well
14 as a portion of the Company-owned facilities included in the Renewable Energy Plan ("RE
15 Plan"), as shown on lines 15 through 26 of Exhibit A-160 (MLM-1). Fixed expenses
16 include, but are not limited to, purchases of fixed energy and capacity, as well as renewable
17 energy transfer costs for a portion of the Company-owned facilities included in the RE
18 Plan, as shown in lines 28 through 33 of Exhibit A-160 (MLM-1).

19 **Q. Please explain any difference between the 2026 and 2027 forecasts filed as part of the**
20 **2025 PSCR Plan filing, and the forecast presented in this electric rate case filing.**

21 A. The PSCR costs are included in this filing as a forecast of expenses for the projected test
22 year beginning May 1, 2026 and ending April 30, 2027 as opposed to the full 2025 calendar
23 year cost projections presented in the 2025 PSCR Plan filing (Case No. U-21592).

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1 Additionally, updated information for all main inputs mentioned above were included in a
2 February 2025 update of the PSCR model previously utilized in support of the 2025 PSCR
3 Plan. Changes include updated forecasts for electric sales, fuel pricing, generation outage
4 schedules, and PPAs, including deferred commercial operation dates (“CODs”) for PPAs
5 due to various issues such as supply chain material delays and renewable site permitting
6 challenges.

7 **Q. Please detail the line items in Exhibit A-160 (MLM-1).**

8 A. Total system requirements (expressed in units of MWh) for the projected test year ending
9 April 30, 2027 are shown on page 1, line 14, and are based on projections provided by
10 Company witness Breuring.¹ Category-level detail comprising the total system
11 requirements is shown on page 1, lines 1 through 13, and is the output of the Aurora
12 production cost modeling and supplied inputs mentioned above.

13 The total annual fuel and variable purchased and net interchange PSCR expense,
14 excluding any fixed energy and capacity expense, is shown on page 1, line 27 (expressed
15 in units of thousands of dollars). This information was derived using production cost
16 simulations and inputs as previously discussed. Exhibit A-160 (MLM-1), lines 28 through
17 33, present the fixed and capacity-related costs included in PSCR expense.

18 Line 35 shows the projected transmission expense that is expected to be recovered
19 as part of the Company’s power supply costs in PSCR proceedings. In Case No. U-14274,
20 the Commission ordered that transmission costs are approved for inclusion in the
21 Company’s PSCR Plan and Reconciliation filings.

¹ The small variance in total MWh between Exhibit A-160 (MLM-1) and Exhibit A-15 (EMB-2), Schedule E-1, is due to timing differences between production cost modeling and changes to generation requirements.

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1 Lines 36 and 38 through 41 show reagent expenses for pollution control at the
2 Company's fossil generation plants which are expected to be recovered as part of the
3 Company's power supply costs in PSCR proceedings.

4 The total PSCR costs are shown on Exhibit A-160 (MLM-1), page 1, line 42.
5 A portion of the PSCR expense is recovered under the LTILRR and a portion of the PSCR
6 expense is recovered under the LED Rate. These amounts are shown on page 1, lines 43
7 and 44, and the remaining PSCR expense to be recovered from remaining full-service
8 customers is shown on page 1, line 44.

9 Pages 2 and 3 of Exhibit A-160 (MLM-1) summarize the purchased and net
10 interchange power volumes and corresponding expenses or revenues projected to be
11 incurred by the Company in the projected test year. These pages detail the volume
12 associated with purchases from NUGs and markets shown in the Total Received, page 2,
13 line 50, with deliveries shown in the Total Delivered, page 2, line 53, category of Exhibit
14 A-160 (MLM-1).

15 **Q. Please explain the expenses for Company-owned resources included in the RE Plan.**

16 A. In general, for most Company-owned resources, there is no fixed expense included in
17 PSCR expenses. The exception² to this is presented on page 1, line 29, of Exhibit A-160
18 (MLM-1) where the Company-owned renewable capacity (or fixed-expense related)
19 component of the transfer price associated with the Company's owned renewable resources
20 is provided, complementing the energy (or Company-owned variable-expense related)
21 component of the transfer price presented on page 1, line 19, of Exhibit A-160 (MLM-1).

² Fixed expense related to transfer costs is an allowable cost included in PSCR cases under Public Act 295 of 2008 ("Act 295"), as modified under Public Act 235 of 2023, the Clean and Renewable Energy and Energy Waste Reduction Act. MCL 460.1047(2)(b)(iv).

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1 **Q. Please explain how PPAs are structured.**

2 A. PPAs include both fixed and variable costs. Some PPAs define payments as “capacity”
3 payments, “fixed energy” payments, and “variable energy” payments. Capacity payments
4 and fixed energy payments are generally regarded as fixed expense because they are
5 expected to be incurred regardless of the amount of energy delivered by the supplier.
6 Variable energy payments generally reflect the cost of purchasing a MWh of energy from
7 a supplier and thus vary depending on the amount of energy delivered. Variable energy
8 payments therefore are similar to the variable expense (e.g., fuel cost) associated with
9 producing a MWh of energy at a Company-owned facility.

10 Some other PPAs provide for a single price to be paid for each unit of energy to be
11 delivered based on a capacity price and a combined fixed and variable energy price.
12 Generally, these types of contracts are not dispatchable by the Company, thus the amount
13 to be paid is likely limited by the physical capability of the supplying facility. In these
14 instances, we have estimated the fixed energy costs based on the rates upon which the
15 contracts were originally modeled.

16 Under Act 295, other PPAs are included in the Company’s rates based on the
17 amount of cost allowed under state law to be transferred from the Company’s Incremental
18 Cost of Compliance to its PSCR costs through the transfer price mechanism. To estimate
19 the amount of capacity, fixed energy, and variable energy expense associated with these
20 transfer costs, the Company used the energy and capacity schedules approved by the
21 Commission in Act 295 and through the Company’s Annual Renewable Energy Cost
22 Reconciliation Proceedings to determine the transfer expenses.

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1 Energy or variable cost-related expense for the Company's PPAs is shown on
2 Exhibit A-160 (MLM-1), page 1, line 25, labeled "Purchased (NUGs) Variable Cost."
3 Capacity or fixed cost-related expense for the Company's PPAs is shown on Exhibit A-160
4 (MLM-1), page 1, lines 31 and 32, labeled "Purchased (NUG) Capacity" and "Purchased
5 (NUG) Fixed Energy," respectively.

6 **Q. For line items 28 through 33 shown on Exhibit A-160 (MLM-1), what are the fixed**
7 **expenses in the PSCR forecast?**

8 A. The Company is forecasting \$2,288,633,000³ of PSCR expense expected to be incurred
9 during the projected test year ending April 30, 2027, of which \$366,140,000⁴ is fixed
10 expense.

11 **Q. Are the projected fuel expenses and the projected purchased and interchanged power**
12 **expenses shown on Exhibit A-160 (MLM-1) subject to any uncertainty?**

13 A. Yes. The expenses are based on projections made by the Company of fuel costs, customer
14 demand, generating unit availability, P&I power availability, P&I power prices, inflation,
15 and other factors that cannot be predicted with precision. These projections were based on
16 the best available information at the time the production cost modeling was completed to
17 support this proceeding. It follows that any results from the use of these projections provide
18 a reasonable but uncertain estimate of power supply costs.

³See Exhibit A-160 (MLM-1), page 1, line 42, column (o).

⁴See Exhibit A-160 (MLM-1), page 1, line 34, column (o).

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1 **Q. What has been the Company's recent experience with the delivery of new**
2 **construction PPAs?**

3 A. The Company has experienced changes to five PPA's since September 2024, as listed in
4 Exhibit A-162 (MLM-3). Of the five PPAs, three were terminated and two requested COD
5 delays, with CODs requested for later in 2026.

6 **Q What is your understanding of the basis for the delays and cancellations of PPAs?**

7 A. It is my understanding that the two primary causes of the delays and cancellation of PPAs
8 are supply chain disruptions and site permitting. Extensive delays and cost increases
9 associated with the procurement of renewable energy system components have led to
10 project delays and/or cancellations. In addition, various entities have contested the site
11 permitting for renewable energy systems, further exacerbating the supply chain issues.

12 **Q. What are possible effects of delayed CODs for PPAs on power supply costs?**

13 A. For delays in those PPAs providing capacity in the form of Zonal Resource Credits
14 ("ZRCs"), those delays could result in fewer ZRCs being available for satisfying the
15 Company's capacity requirement in the MISO PRA and may require the Company to
16 procure capacity from the PRA or some other means to meet the Company's Planning
17 Reserve Margin Requirement ("PRMR"). So, while the Company would realize the cost
18 of capacity from the PRA, the PSCR costs would decrease by the amount of the delayed
19 PPA.

20 **Q. Please describe the practices and procedures used by the Company to protect**
21 **customers from PPA cost escalation or COD delays.**

22 A. To protect customers from PPA cost escalation, price is defined as a term of the contract
23 upon execution. If a counterparty requires a price increase to make the project viable, the

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1 Company assesses the amendment request and specifics of the situation and compares other
2 alternatives to determine if the amendment is in the best interest of customers. To protect
3 from COD delays, the contract generally includes penalties, up to and including
4 termination of the contract.

5 **Q. Please summarize your direct testimony regarding power supply charges.**

6 A. The Company anticipates incurring approximately \$2,288,633,000³ in total PSCR
7 expenses during the projected test year ending April 30, 2027, of which \$121,588,000⁵ is
8 expected to be recovered under the LTILRR, \$63,092,000⁶ is expected to be recovered
9 from LEDR, and \$2,103,953,000⁷ is expected to be recovered from remaining full-service
10 customers.

11 **SRM – CAPACITY CHARGE REVENUE OFFSETS AND DEMAND**

12 **Q. Please describe the SRM Capacity Charge.**

13 A. In the Commission’s November 21, 2017 Order in Case No. U-18239 (“November 21
14 Order”), the Commission adopted a methodology for determining the SRM Capacity
15 Charge pursuant to Public Act 341 of 2016. The capacity charge “is a retail rate, designed
16 to recover the incumbent utility’s cost of providing capacity service, to whatever type of
17 customer load – bundled or choice” (November 21 Order, page 73) to ensure long-term
18 resource adequacy to customers in the state.

19 **Q. How is the capacity charge determined?**

20 A. Company witness Davis’s direct testimony describes how the capacity charge is calculated
21 and what inputs are utilized in the calculation. As discussed in Company witness Davis’s

⁵ See Exhibit A-160 (MLM-1), page 1, line 43, column (o).

⁶ See Exhibit A-160 (MLM-1), page 1, line, 44, column (o).

⁷ See Exhibit A-160 (MLM-1), page 1, line 45, column (o).

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direct testimony, the SRM Capacity Charge calculation includes capacity cost offsets and a capacity charge demand used as the denominator of the capacity charge. These inputs rely on data that is detailed in this direct testimony below.

Q. Please define capacity cost offsets.

A. Capacity cost offsets are projected revenue(s) and associated fuel costs that are subtracted from the calculated capacity-related cost in developing the SRM Capacity Charge.

Q. Please identify the capacity cost offsets.

A. The capacity cost offsets used in the SRM calculation are:

- (i) Energy Market Sales Revenue of \$871,945,000 (line 12, Exhibit A-161 (MLM-2));
- (ii) Off-System Energy Sales of \$9,000,000;⁸
- (iii) Ancillary Service Sales of \$5,000,000;
- (iv) Bilateral Energy Sales of \$0; less
- (v) Related Fuel Costs of \$545,993,000 (line 24, Exhibit A-160 (MLM-1)).

Q. What is the basis for the above capacity cost offsets?

A. The Energy Market Sales offset is derived from the monthly volume of energy produced by generators owned or controlled by the Company as extracted from the Company's forecast of power supply costs for the projected test year (sum of lines 1 through 8 and lines 10 and 12 in Exhibit A-160 (MLM-1)) multiplied by the Company's forecast of the average monthly locational marginal price. The Off-System Energy Sales offset is based on the actual 2024 energy sales made to the Company's sole non-jurisdictional wholesale customer. The Ancillary Service Sales offset is based on the most recent-year historical value in this case. The Company made no bilateral energy sales in 2024 and does not

⁸ 2024 Actual Off-System Energy Sales, Ancillary Service Sales and Bilateral Energy Sales from Case No. U-21424, Exhibit A-30 (RTS-3) line 2, lines 3-4, and line 5, respectively.

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1 forecast to make any bilateral energy sales in the projected test year ending April 30, 2027.
2 Related Fuel Costs are the forecasted variable costs associated with the volume of Energy
3 Market Sales as extracted from the Company's forecast of power supply costs for the test
4 year (Exhibit A-160 (MLM-1), page 1, line 24).

5 **Q. Is the Energy Market Sales offset the same as the Net Interchange Credits shown on**
6 **Exhibit A-160 (MLM-1), page 3?**

7 A. No. The Energy Market Sales offset is representative of the energy market value of the
8 Company's entire generation fleet and PPAs and is calculated by multiplying the monthly
9 energy produced by those resources by the forecasted average monthly locational marginal
10 price. The Net Interchange Credit is the energy revenue of the generation fleet and PPAs
11 sold into the MISO energy market in excess of the Company's load as calculated on an
12 hourly basis. The Net Interchange Credit has been steadily declining over previous years
13 due to reduced sales and increased load. The two numbers explained above are derived
14 from the same PSCR model (Aurora) and start from the same data source but are calculated
15 and utilized differently in the filing.

16 **Q. What is the value and source for the Capacity Charge Demand used in the SRM**
17 **Capacity Charge calculation?**

18 A. The Capacity Charge Demand value is 9,853 MW. This value represents Consumers
19 Energy's actual total supply, including ROA, recorded in 2024. This value is sourced from
20 the Company's most recent Securities and Exchange Commission Form 10-K filing,
21 consistent with the Commission's determination in Case No. U-20963.

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1 **Q. What is the resulting SRM Capacity Charge that is proposed in this case?**

2 A. As described by Company witness Davis, the SRM Capacity Charge calculation that is
3 being proposed in this case is \$116.17/MW-day.

4 **Q. How does the SRM Capacity Charge proposed in this case compare to the SRM**
5 **Capacity Charges approved in prior rate cases filed by the Company?**

6 A. The SRM Capacity Charge approved was: \$65.13/MW-day in Case No. U-21585;
7 \$76.62/MW-day in Case No. U-21389; \$244.80/MW-day in Case No. U-21224;
8 \$328.26/MW-day in Case No. U-20963; and \$374.95/MW-day in Case No. U-20697.

9 **Q. Have there been any proposed revisions to the SRM Capacity Charge calculation in**
10 **previous cases?**

11 A. Yes. In several previous cases, including Case Nos. U-20697, U-20963, U-21389, and
12 U-21585, the Company proposed to use the ZRC value assigned to the Company's capacity
13 resources in the denominator of the SRM Capacity Charge. In Case No. U-20963 the
14 Company proposed to amend an input for the Capacity Cost Offsets calculation, more
15 specifically to include variable expense incurred by PPAs in the Related Fuel Costs offset.
16 Additionally, in Case No. U-21585, Staff witness Nicholas M. Revere proposed that the
17 SRM Capacity Charge calculation include an offset for the Company's net sales,
18 effectively reducing the capacity cost for the Company, and ultimately ensuring
19 unnecessary cost burden is not passed on to the customer.

20 **Q. Were the SRM Capacity Charge calculation changes proposed by the Company**
21 **approved by the Commission?**

22 A. No. The proposals were rejected by the MPSC, based on the argument that the method for
23 calculating the SRM Capacity Charge was originally approved in Case No. U-18239 and

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1 that any proposed changes to the calculation methodology would require that case be
2 re-opened.

3 **Q. Has the Company proposed any revisions to the SRM Capacity Charge calculation in**
4 **this case?**

5 A. No. The Company has not proposed any changes to the SRM Capacity Charge calculation
6 in this case. However, following the Commission's prior guidance, the Company intends
7 to further evaluate re-opening the original SRM Case No. U-18239 to propose a calculation
8 methodology that does not result in a SRM Capacity Charge that prevents recovery of the
9 Company's full capacity costs and, as a result, unfairly harms full-service customers.
10 Additionally, the introduction of MISO's new Seasonal Construct, as I describe later in this
11 direct testimony, will also impact the need to change the SRM Capacity Charge
12 calculation's current calculation methodology.

13 **Q. What is the SRM reconciliation calculation?**

14 A. Per Section 6w(4) of Act 341, the SRM reconciliation calculation or "true-up mechanism"
15 shall reconcile the differences between projected and actual net revenues of energy market
16 sales above the Company's service requirements, fuel costs, and capacity costs. Should an
17 SRM Capacity Charge be imposed, any over/under collection will be corrected in the
18 subsequent year's capacity charge.

19 **Q. Has the Company included the SRM reconciliation amount in this proceeding?**

20 A. Yes. Although the Company has never implemented the SRM Capacity Charge, as ordered
21 by the Commission in Case No. U-21585, the Company has included the SRM
22 reconciliation amount, as shown on line 19 of Company witness Davis's Exhibit A-16
23 (EAD-2), Schedule F-1.1.

ELECTRIC GENERATION CAPACITY

Q. In his direct testimony, Company witness Blumenstock proposes capital investment and operating and maintenance expenses necessary to support the Company's electric generation fleet. Why is this spending important for the Company's customers in the context of electric supply and capacity planning?

A. As Company witness Blumenstock explains in his direct testimony, the Company owns a diverse electric generation fleet comprised of fossil fuel, renewable (including hydroelectric), and pumped storage assets. These assets are prudently managed and operated to ensure the supply of reliable and cost-effective electricity for customers. Continued investment and spending in the generation units are necessary to maximize the economic benefit delivered to customers in the form of both energy and capacity value. Company witness Blumenstock provides a description of Net Energy Value ("NEV"), which the Company utilizes to analyze and quantify a generation asset's net benefit (relative to cost) to the Company's customers on an energy basis. From a capacity perspective, maintenance of the generation fleet is necessary to ensure the Company can meet resource adequacy obligations with MISO, as further described below. Both the energy and capacity value of the generation units ultimately underpin the power supply costs as presented earlier in this direct testimony.

Q. What is the connection between the generation reliability spending proposed by Company witness Blumenstock and the capacity from those assets?

A. As discussed by Mr. Blumenstock, generation reliability investments are expected to maintain or improve unit availability and reliability. Improvements in unit availability are expected to produce a corresponding improvement in the Seasonal Accredited Capacity

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1 (“SAC”) for those generating units. SAC is defined within the MISO Resource Adequacy
2 Business Practice Manual BPM-011⁹ as the anticipated capacity and availability of
3 planning resources during times when they are most needed. Improvement in SAC and
4 ensuring unit availability translate into increased capacity credit received from MISO in
5 the form of ZRCs as well as increased NEV for the generating units. Company witness
6 Blumenstock provides additional discussion on the value of minimizing ROR and
7 improving generating unit availability. The increased capacity credit is part of the
8 Company’s plans for meeting future PRMR and reducing cost associated with the need to
9 purchase third-party or market based ZRCs.

10 **Q. Please explain the MISO seasonal resource adequacy construct?**

11 A. On August 31, 2022, FERC accepted MISO’s proposal to implement seasonal resource
12 adequacy requirements effective for the 2023/2024 planning year (see Case No. ER22-495-
13 000, et al.). MISO’s “seasonal construct” requires Load Serving Entity’s (“LSEs”) to meet
14 the peak demand and load requirements for one peak hour per season (Summer, Fall,
15 Winter, Spring). Summer season is defined as June 1 through August 31, Fall season is
16 defined as September 1 through November 30, Winter season is defined as December 1
17 through last day in February, and Spring season is defined as March 1 through May 31.
18 MISO’s stated intended outcomes of moving to a Sub-Annual Resource Adequacy
19 construct are to (1) identify reliability needs unique to each season, (2) align resource
20 availability with seasonal needs, and (3) facilitate seasonal outages or partial year
21 operations.

⁹ Available at <https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/>,
accessed October 01, 2024.

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1 In addition to the change from an annual to a sub-annual construct, MISO also
2 changed the capacity accreditation methodology for thermal generating units and DR
3 Resources. The capacity accreditation methodology changed from an Unforced Capacity,
4 summer-focused construct, to a two-tier system based on real-time availability, with
5 emphasis on the highest risk periods for each season. MISO has not changed the capacity
6 accreditation methodology for non-thermal resources currently, except to adjust for
7 seasonality.

8 **Q. Please explain PRMR.**

9 A. The PRMR is defined by MISO in the Resource Adequacy Business Practice Manual
10 BPM-011 as the number of MW in ZRCs required to meet a LSEs Resource Adequacy
11 Requirements ("RAR"). The RAR is established to ensure that LSEs have enough
12 Planning Resources to reliably serve load for the applicable seasons. Consumers Energy
13 is an LSE and is required to maintain sufficient capacity to ensure adequate electric supply
14 in each Planning Year period for the projected LSE's load. The Company relies on MISO
15 to determine the appropriate PRMR Consumers Energy should maintain. The PRMR is
16 calculated by MISO using: (i) the Company's forecast peak load coincident to MISO's
17 peak load; (ii) a transmission loss percentage applicable to the Company; and (iii) a reserve
18 margin to ensure reliability.

19 **Q. Please explain what a ZRC is and how ZRCs are currently awarded for the**
20 **Company's generation assets.**

21 A. For thermal generation resources, a ZRC is a capacity credit increment equal to 1 MW of
22 generation resource, adjusted by its availability which is based on the SAC calculation.
23 The SAC calculation reflects the anticipated capability and availability of a generation

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1 resource during times when they are most needed. This two-tier weighing structure is
2 based on its real-time offered availability during seasonal Resource Adequacy (“RA”)
3 hours (Tier 2) and Non-RA hours (Tier 1). Resource Adequacy hours are based on
4 emergency events, the tightest operating margin hours and maximum operating margin
5 threshold. Operating margin is the amount of MW available divided by the amount of
6 system load.

7 For intermittent generation resources, a ZRC is a capacity credit increment equal to
8 1 MW of generation resource, adjusted by its availability, which is based on historical
9 performance during critical hours within each season, where new resources receive class
10 average for that resource type until required historical data is accrued.

11 For reservoir hydroelectric facilities such as Ludington Pumped Storage, a ZRC is
12 a capacity credit increment equal to 1 MW of generation resource, adjusted by its
13 reliability, which is based on the Demand Equivalent Forced Outage Rate (“EFORD”)
14 calculation. Over each three-year period, startup, run time, and outage information is
15 collected and categorized to determine the EFORD value for each generator. Prior to each
16 Planning Year, MISO awards ZRCs to generator owners based on the lesser of the
17 interconnection service limit and the Generation Verification Test Capacity (“GVTC”),
18 multiplied by the result of one minus EFORD.

19 **Q. What is the ultimate effect of obtaining ZRCs for generating units?**

20 A. The Company’s sustained capital investment in generator reliability allows the Company
21 to maintain or improve the availability of its units and, as a result, maintain or increase the
22 amount of ZRCs and the corresponding value realized to customers in the future. These
23 ZRCs are a key component of meeting the Company’s PRMR and mitigating customer

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1 exposure to capacity price risk from insufficient capacity resources to meet the Company's
2 PRMR.

3 **Q. Please describe the result if no additional investments are made.**

4 A. If no additional investments are made, the deterioration of a plant's reliability is expected
5 to increase over time, reducing the ZRCs assigned to the generating unit and therefore
6 reducing the capacity value of the facility.

7 **Q. How is capacity value determined?**

8 A. MISO administers a PRA annually, which "clears" seasonal ZRC offers to satisfy 100% of
9 seasonal PRMR for each LSE. If sufficient resources are not available, the PRA cost of
10 capacity may be driven as high as Cost of New Entry ("CONE"). CONE is an
11 industry-wide concept that represents the fixed costs of constructing and operating a new
12 source of power to provide capacity. In the case of MISO, CONE represents the cost of
13 constructing and operating a new simple cycle gas turbine fueled generator.

14 **Q. At what cost has the CONE been set in recent years?**

15 A. The CONE has been set at the following costs in recent years for MISO Zone 7:

- 16 • Planning Year 2021/2022: \$259.73/ZRC-day;
- 17 • Planning Year 2022/2023: \$236.66/ZRC-day;
- 18 • Planning Year 2023/2024: \$289.37/ZRC-day;
- 19 • Planning Year 2024/2025: \$347.36/ZRC-day; and
- 20 • Planning Year 2025/2026: \$358.71/ZRC-day.

21 **Q. For comparison, what was the clearing price for capacity in MISO Zone 7 for each of**
22 **the above Planning Years?**

23 A. MISO Zone 7 cleared at the following prices in recent years:

- 24 • Planning Year 2021/2022: \$5.00/ZRC-day;

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- Planning Year 2022/2023: \$236.66/ZRC-day;
- Planning Year 2023/2024:
 - o Summer Season: \$10.00/ZRC-day;
 - o Fall Season: \$15.00/ZRC-day;
 - o Winter Season: \$2.00/ZRC-day; and
 - o Spring Season: \$10.00/ZRC-day.
- Planning Year 2024/2025:
 - o Summer Season: \$30.00/ZRC-day;
 - o Fall Season: \$15.00/ZRC-day;
 - o Winter Season: \$0.75/ZRC-day; and
 - o Spring Season: \$34.10/ZRC-day.

Q. If the cost of capacity were to go to CONE, how would the Company's capacity cost be affected?

A. If MISO Zone 7 clears at CONE, as it did in Planning Year 2020/2021 and Planning Year 2022/2023, it is a signal that the Zone does not have enough capacity to meet the Zone's PRMR, which in turn means that there is an increased risk of system-wide reliability issues. If the Company is a net purchaser of capacity in a given year, an Auction Clearing Price of CONE could result in price increases to the Company's customers.

Q. What conclusion have you reached relative to the generation spending being sponsored by Company witness Blumenstock?

A. The capital investment in the Company's generation fleet will provide for reliable and cost-effective power supplied to customers. This is true for both energy and capacity, where capacity is particularly necessary to meet resource adequacy obligations (i.e. PRMR) and avoid purchasing potentially high-cost capacity from the MISO capacity market.

DEMAND RESPONSE CAPACITY

Q. Please explain the types of DR programs expected to be employed by the Company in 2025 and 2026.

A. The Company's DR programs planned for 2025 and 2026 fall into one of two categories: (1) those that are directed by the Company; or (2) those that are dependent upon customer behavioral choices. DR programs controlled by the Company supply either a fixed quantity or range of energy. DR programs that are dependent upon customer behavioral choices provide energy reduction driven by rate structures that incentivize customers to use less energy during peak electric load periods. Additional details for specific DR programs are provided in the direct testimony of Company witness Gast.

Q. How are DR programs valued in terms of capacity credit in MISO's capacity market?

A. ZRCs are awarded by MISO for the Company's DR programs that are directed by the Company and registered by the Company as a capacity resource. The ZRCs are used to satisfy the Company's annual PRMR. For DR programs that are dependent upon customer behavioral choices, the Company reduces its peak load forecast by the amount of the DR programs that are expected at peak load conditions. This reduction directly reduces the Company's PRMR.

Q. What are the forecasted DR Program levels for Planning Year 2025/2026 and 2026/2027?

A. For Planning Year 2025/2026 and 2026/2027, the Company will administer five DR programs that are controlled by the Company, including Air Conditioning Peak Cycling, Smart Thermostat Program, DR Contracts, DR Rate GI Reduce By, and DR Rate GI Reduce To. The total planned capacity of these DR resources to be registered with MISO

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1 in the summer season is approximately 651 ZRCs in Planning Year 2025/2026 and 684
2 ZRCs for Planning Year 2026/2027.

3 Also, for Planning Years 2025/2026 and 2026/2027, the Company will continue
4 demand-side management programs that are dependent upon customer behavior, including
5 Dynamic Peak Pricing, Energy Waste Reduction, Conservation Voltage Reduction, and
6 Residential Summer on-peak rate. The total of these programs is approximately 1,023 MW
7 for Planning Year 2025/2026 and 1,144 MW for Planning Year 2026/2027.

8 Per the MISO standard practice for demand-side management capacity planning,
9 ZRC values reflect the expected MW reductions plus adjustments for transmission losses,
10 planning reserve margin, and load diversity factors.

11 **Q. What is the approximate market value of these DR resources?**

12 A. Consumers Energy's Planning Year 2025/2026 DR portfolio is projected to total
13 651.4 ZRCs, valued at \$62 million at an estimated value of capacity of \$95,351/ZRC-
14 Year.¹⁰ Consumers Energy's Planning Year 2026/2027 DR portfolio is projected to total
15 684.3 ZRCs, valued at \$65 million at an estimated value of capacity of \$95,351/ZRC-Year.
16 Similar to the generation capacity discussion earlier in this direct testimony, continued
17 investment in growing the Company's DR programs is important to the Company's electric
18 supply strategy (meeting PRMR obligations and avoiding potentially higher-cost market
19 capacity purchases) and its broader Clean Energy Plan to further integrate cleaner supply
20 and demand-side resources to cost-effectively meet customer demand.

¹⁰ Based on 75% of MISO's calculated Planning Year 2024/2025 CONE.

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1 **Q. Are you supporting any projected capital expenditures for IT related projects in the**
2 **test year?**

3 A. Yes. I am supporting an IT project for the PCI platform named the Integrated Energy
4 Management Platform Optimization project. The test year capital expenditure amount is
5 \$1,343,299 and the projected test year O&M is \$507,797. These amounts are reflected in
6 Exhibit A-12 (SHB-4), Schedule B-5.1, line 3, and Exhibit A-19 (SHB-3), line 1,
7 respectively, from Company witness Stacy H. Baker.

8 **Q. Please describe the PCI Platform.**

9 A. PCI provides software the Company uses to fulfill the FERC requirement of
10 communicating unit availability to MISO to efficiently buy and sell electricity in the
11 wholesale market.

12 **Q. Please describe the value of the planned capital IT investment in optimizing this**
13 **platform.**

14 A. The Integrated Energy Management Platform Optimization project will reduce data center
15 assets running PCI by migrating from on-premises into cloud services. This will optimize
16 vendor support, reduce on-going operational costs (upgrades, server maintenance), and
17 allow the Company to leverage new cloud capabilities.

18 Due to PCI currently being on-premise, the Company is not able to leverage
19 benefits of the functionality in the vendor's cloud hosting solution (Software as a Service
20 ("SaaS")). The break/fix, maintenance, and upgrades of the current solution (including
21 application and infrastructure) require Company resources and the associated labor
22 expenses to support. In addition, the infrastructure platform requires additional licensing

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1 and costs that the Company is planning to eliminate with the service moving from
2 on-premise to the cloud.

3 This project creates value for the Company by: (1) utilizing the vendor's SaaS
4 environment to provide efficiencies for timely operational support. As an example, IT
5 currently sends PCI a database copy so they can replicate the Company's environment in
6 the vendor's system. Moving to the cloud eliminates the need for this step, thus reducing
7 resource needs, time, and increased support costs. (2) Freeing up resources for more
8 value-add work. (3) Reducing CE maintained Oracle server footprint, retiring all existing
9 infrastructure so no future maintenance or complex licensing requirements will be needed.
10 (4) reducing IT labor support costs. (5) reducing ongoing networking equipment
11 replacement and upgrade costs.

12 **Q. What is the scope of this project?**

13 A. The project scope includes: (1) planning and executing the data migration; (2) designing
14 and configuring new and existing vendor SaaS components; (3) implementing integrations
15 to COTS (Commercial Off-The-Shelf) and custom systems; (4) testing; (5) education and
16 training from PCI, increasing the skills of the employees to leverage the new vendor SaaS
17 services and create job aids and runbooks for the support teams; and (6) decommissioning
18 old infrastructure.

19 **Q. What alternatives were considered?**

20 A. Alternatives considered include: (1) continue to use the on-premise installation of PCI.
21 This alternative was not chosen due to the significant waste involved in maintaining the
22 system, the inability to leverage cloud functionality, and the failure to decrease the reliance
23 on Oracle servers. (2) Move to a different energy market platform. This alternative was

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1 not selected because the different platform would have lesser options and would not be
2 able to utilize PCI's bid to build process. (3) Move to the vendor SaaS. This alternative
3 was selected as the Company will utilize the latest technology and optimize operational
4 support.

5 **Q. Does this conclude your direct testimony?**

6 **A. Yes.**

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

JEFFREY A. MYROM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

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1 **Q. Please state your name and business address.**

2 A. My name is Jeffrey A. Myrom, and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
6 as Director of Electric Vehicle Customer Programs.

7 **Q. What are your responsibilities as Director of Electric Vehicle Customer Programs?**

8 A. As Director of Transportation Electrification Programs (“TEPs”), I lead the teams for
9 Consumers Energy’s PowerMIDrive Residential, PowerMIDrive Public Charging, and
10 PowerMIFleet customer programs.

11 **Q. Please describe your educational background and professional experience.**

12 A. I have a Master of Science Degree in Environmental Policy from Michigan Technological
13 University, and a Bachelor of Chemistry, Environmental Science and General Science from
14 Coe College.

15 From 2001 to 2006 I served as Deputy Bureau Chief of the Iowa Department of
16 Natural Resources’ Energy & Waste Management Bureau (“Bureau”). In that role,
17 I directed all administrative rules processes and amendments for the Bureau. I also
18 represented the Bureau in matters before the Environmental Protection Commission and
19 Iowa Legislature on policy and administrative rules issues.

20 In 2006, I became employed by MidAmerican Energy, now known as Berkshire
21 Hathaway Energy. In that position, I served as Senior Environmental Policy Analyst,
22 representing MidAmerican Energy on issues related to waste, water, climate, renewable
23 energy, and electric generation resource modeling and planning.

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1 In January 2013, I was employed by Consumers Energy Company as Director of
2 Environmental Regulations, Strategy, and Sustainability. In May 2018, I was promoted to
3 Director of Renewable Energy and Electric Vehicle Customer Products. In this position,
4 I was responsible for administering and expanding the Company's Voluntary Green
5 Pricing programs. Additionally, under my direction, the Company successfully launched
6 the PowerMIDrive pilot in June 2019, approved by the Michigan Public Service
7 Commission ("MPSC" or the "Commission") in Case No. U-20134, and later approved as
8 a permanent residential program in Case No. U-21224. In June 2021, under my direction,
9 the Company also successfully launched the PowerMIFleet pilot that was approved by the
10 Commission in Case No. U-20697, and expanded for fleets serving income qualified
11 communities in Case No. U-20963.

12 In July 2021, I was promoted to my current position as Director of Electric Vehicle
13 Customer Products. In this position my responsibilities were expanded with the growing
14 pilots, and now include additional team members for the administration of PowerMIFleet,
15 PowerMIDrive Public Charging and PowerMIDrive Residential as permanent programs in
16 the Company's TEP that will benefit all customers.

17 **Q. What is the purpose of your testimony?**

18 A. The purpose of my testimony is to propose enhancements to the TEPs that will continue to
19 improve customer experience and benefits without any budgetary increase from prior
20 MPSC approvals. For this testimony, the term electric vehicle ("EV") will be used to
21 collectively describe all forms of EVs, including battery electric vehicles ("BEVs") and
22 plug-in hybrid electric vehicles ("PHEVs").

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1 **Q. Have you previously testified before the Commission?**

2 A. Yes, I have previously provided testimony in the Company's 2019 Voluntary Green Pricing
3 application (Case No. U-20649), 2021 Renewable Energy Plan amendment (Case No.
4 U-20984), 2021 General Electric Rate Case (Case No. U-20963), 2022 General Electric
5 Rate Case (Case No. U-21224), 2023 General Electric Rate Case (Case No. U-21389), and
6 2024 General Electric Rate Case (Case No. U-21585).

7 **Q. Are you sponsoring exhibits in this case?**

8 A. Yes, I am sponsoring three exhibits:

9	Exhibit A-12 (JAM-1)	Schedule B-5.8	Transportation Electrification
10			Plan Capital Expenditures;

11	Exhibit A-164 (JAM-2)		Transportation Electrification
12			Plan Deferred Asset Costs;
13			and

14	Exhibit A-165 (JAM-3)		Transportation Electrification
15			Plan Cost Benefit Analysis.

16 **Q. Were these exhibits prepared by you or under your direction or supervision?**

17 A. Yes.

18 **Q. Please describe Exhibit A-12 (JAM-1), Schedule B-5.8.**

19 A. Exhibit A-12 (JAM-1), Schedule B-5.8 reflects the capital spend for the historical, bridge,
20 and test years for the TEPs per approvals from prior rate cases. Make-ready capital
21 includes metering and utility-side upgrades such as transformers for new services as
22 previously approved. No additional spend from prior approvals is requested, but the
23 timeline has changed. The Company had anticipated that all remaining capital for the
24 initial fast charging pilot authorization would be complete in 2025; however, factors such
25 as National Electric Vehicle Infrastructure ("NEVI") contracting delays and the Federal

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Highway Administration's decision to suspend EV charging infrastructure funding has extended the completion date for multiple projects.

Q. Please describe Exhibit A-164 (JAM-2).

A. Exhibit A-164 (JAM-2) shows spending in this case for TEPs' assets, per approvals from prior rate cases. Again, no additional spend from prior approvals is requested.

Q. Please describe Exhibit A-165 (JAM-3).

A. Exhibit A-165 (JAM-3) summarizes the costs and revenues from optimized EV load growth via the TEPs. The positive NPV clearly shows that the additional load growth from EVs creates margin that exceeds the TEPs revenue requirement and other costs. Thus, the TEPs do not increase rates but instead mitigate rate pressure for all customers.

Q. Please summarize the Company's approved TEP programs and their results.

A. Per the Final TEP Order in Case No. U-21492,¹ the Company TEP is centered on long-term strategies to optimize EV charging load to the benefit of all customers, and investments, incentives, programs, and expenditures that are reasonably expected to increase transportation electrification in the Company's electric service territory. The Company's latest TEP is publicly available online² and while filed prior to the Final Order via Case No. U-21492, is recognized by the Commission as sufficient for planning purposes until July of 2026, by which time an updated TEP will be filed by the Company.

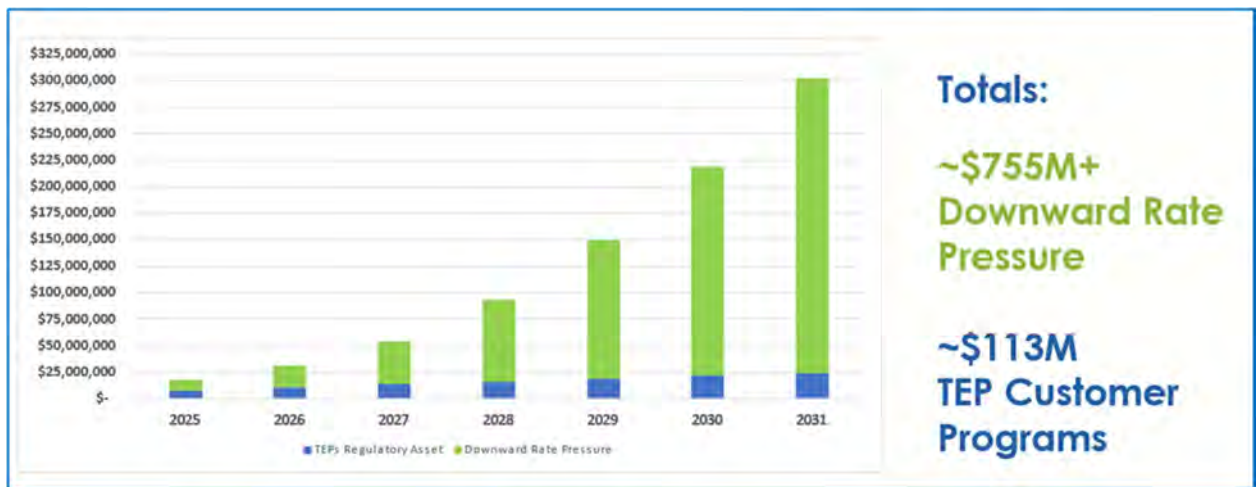
To accomplish the goals of optimizing load and increasing transportation electrification, the Company continues to support utilizing a portion of the additional

¹ MPSC Case No. U-21492, January 23, 2025 Order, at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000X2NGsAAN> (adopting the final Transportation Electrification Plan Filing Requirements as filed by the MPSC Staff on January 24, 2025).

² MPSC Case No. U-21538, June 25, 2024 Consumers Energy Transportation Electrification Plan 2024 (2024 TEP Report), at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000EFQgtAAH>.

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revenue from EV load growth to pay for TEPs. This is optimal because EV drivers pay for the TEPs and the Company is not raising rates to implement the TEPs. Moreover, while EV drivers fully pay for the TEPs, all customers benefit from the load optimization as the same infrastructure is used to power more EVs, generating additional revenue that mitigates rate pressure. This is clearly shown in the “Cost Benefit Analysis” tab of Exhibit A-165 (JAM-3) and illustrated in the graphic below by comparing the TEPs cost recovery from line 1 in blue, to the total remaining margin after all costs from line 22 in green.



Furthermore, the Company has been highly successful at optimizing EV load growth via its TEP, exceeding the State goal of 80% or more off-peak charging.³ In fact, in 2023 the Company won the Peak Load Management Alliance Pacesetter award for the best utility EV load management program in the United States, given that residential participants (the largest component of the TEPs) commonly achieves near 95% off-peak charging. Moreover, in early 2025, the Company won the Electric Power Research Institute’s (“EPRI’s”) Technology Transfer Award for applying EPRI and Company

³ See 2024 TEP Report, page 39, at [0688y00000EFQgtAAH](#).

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1 research and converting it into load management and EV planning success. The Company's
2 TEP is a national model for EV load management.

3 To optimize load and increase EV adoption, the Company is focused on three key
4 strategic program areas within the TEP umbrella – Residential, Public and Fleet:

5 **Residential** – Being able to reliably and cost-effectively charge at home is critical
6 for most EV drivers, thereby directly impacting EV adoption because if you don't have
7 convenient home charging you are less likely to adopt the technology. Moreover, most
8 homes in Michigan were constructed before EVs became mainstream, meaning that load
9 management is critical given constraints at the panel and potentially the residential
10 distribution system.

11 The single-family programming implements a combination of educational
12 outreach, Time-of-Use ("TOU") rate, and rebate and incentive programs for off-peak
13 charging at Level 2 ("L2") circuit levels of 50 amps or less (40 amps continuous for
14 9.6 kW) consistent with residential design standards. The up to \$500 rebate (up to \$1,000
15 for income-qualified customers) serves to get EV drivers engaged with their utility and the
16 program, as utility service is not historically part of purchasing a vehicle. From the initial
17 customer contact driven by the rebate offer, EV specialists can educate customers on TOU
18 rates and why off-peak charging is beneficial. Once enrolled, the monthly off-peak
19 charging incentive of \$10 (for 12 months) helps reinforce off-peak charging behavior
20 through all four seasons leading to long term off-peak charging behavior.

21 Furthermore, the residential team is presently implementing a referral incentive
22 program, as the most likely people to purchase an EV are those who know someone with
23 an EV, and thus customers in the program are key components of helping to grow

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1 enrollment via other EV drivers and potential drivers they know. Finally, the team is also
2 presently implementing the dual-cord L2 and splitter incentive,⁴ which is designed to
3 prevent EV charging peaks beyond the residential design standards by continuing to utilize
4 a single 50 amp circuit (40 amp continuous) as additional EVs are purchased or leased (a
5 likely occurrence given that most EV drivers remain EV drivers) to spread the load over a
6 longer off-peak time at a maximum 9.6 kW load. Without an incentive for dual-cord L2
7 or use of a power-sharing splitter, it is more likely that continued EV adoption would result
8 in multiple EV charging circuits in a home, leading to peak loads significantly greater than
9 9.6 kW and higher ramp rates.

10 Critically, the Company's residential programming also focuses on multifamily
11 locations, providing equitable charging opportunities at apartments, condos, and
12 townhomes where charging infrastructure is known to be harder to implement.
13 Approximately one in three customers is estimated to live in a multifamily property and
14 with very affordable, used EVs rapidly increasing in market availability, this is an
15 important segment to ensure service for.

16 In multifamily situations where a customer's residential L2 cannot be directly tied
17 to their meter and parking location, the Company offers up to a \$7,500 rebate to add a
18 separate service with at least two plugs powered by 100 amps. The new separate service
19 is usually in a shared parking area, although site hosts can choose if they want to create
20 reserved parking spots and can choose if and how to recoup costs for L2 utilization by
21 residents. The Company also provides signs for display at the charger encouraging

⁴ A dual-cord L2 utilizes two plugs that power share from the same L2. A splitter is a device that plugs into a single outlet, and then two separate L2 power share from that device. Both technologies work via a single NEMA 14-50 outlet.

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1 off-peak charging, literature for property managers relaying the same message, and a
2 \$20 per month bill credit for 12 months when 80% or more of charging is off-peak. Given
3 tenant turnover challenges, the Company is considering if more active but low-cost
4 controls, such as timers to avoid weekday peak hours, may be useful tools to promote
5 off-peak charging as more load data continues to be gathered.

6 **Public** – Public charging advances both grid optimization and EV adoption. Grid
7 optimization is achieved by incentivizing lower-power charging (L2 and L1) at strategic
8 off-peak locations that fit the customer’s use case. A few examples of such off-peak use
9 cases supported by the Company TEP include utilizing a L2 community charger on the
10 weekend or overnight if your multifamily property does not offer charging, using a hotel
11 L2 overnight while on business travel or a campground L2 when family vacationing at our
12 excellent state parks on the Lake Michigan Circuit,⁵ or using an L1 at the airport or ferry
13 station when away on a multi-day trip.

14 Such public charging also assists with EV adoption because knowing a charger
15 exists where you want to travel instills charging confidence, and charging confidence is the
16 inverse of range anxiety (which remains one of the top three concerns regarding EV
17 adoption). Moreover, when public charging resources do not exist at such key locations,
18 existing EV drivers are more likely to not take their EV on the longer trip, which reinforces
19 the stereotype that EVs are only for around town and thus not ready for mainstream
20 adoption.

21 Like the residential multifamily strategy, public L2 and L1 programs utilize
22 educational outreach materials and signage for site hosts, TOU rates, and rebates for

⁵ The “Lake Michigan Circuit” is an initiative by Michigan, Wisconsin, Illinois, and Indiana to build EV charging infrastructure along Lake Michigan to support tourism on the coastline.

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1 off-peak charging of up to \$7,500 per two L2 plugs or five L1 plugs powered by 100 amps.
2 These power levels serve to spread out the load and optimize off-peak utilization of the
3 distribution system.

4 Furthermore, community charging also promotes equity. It encourages developers
5 to reach areas that might otherwise lack access to lower-power charging by creating L2
6 infrastructure within walking distance of multifamily residences.

7 **Fleet** – Fleet and workplace charging also directly address grid optimization and
8 EV adoption. For example, workplace charging is not only largely off-peak (typical
9 commutes can finish charging before noon) but also enables EV adoption by customers
10 who may not have access to charging at their home (which is especially challenging for
11 multifamily residents). Moreover, the fleet program presently focuses on outreach, TOU
12 rate, and rebate programs for small and medium businesses, local governments,
13 non-profits, and educational institutions to incentivize off-peak charging. The additional
14 funding for fleets serving income-qualified customers will continue to allow non-profits
15 and local governments to add cost-effective EVs to their fleet that they may not have been
16 able to afford without the funding. Finally, employees who are exposed to the performance
17 benefits of EVs at work are more likely to buy or lease an EV as their next personal vehicle,
18 thereby increasing EV adoption.

19 The Company's fleet and workplace rebates are up to \$7,500 per two plugs powered
20 by 100 amps, with an enhanced rebate of up to \$10,000 for workplace L2 that also serve as
21 community charging locations overnight and, on the weekend, (a unique value proposition
22 designed to increase equitable access to charging and maximize use of charging
23 infrastructure). Fleet also offers a long-duration direct current ("DC") rebate of up to

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1 \$15,000 per plug of 50 kW or less, focused on medium and heavy-duty vehicles such as
2 electric school buses that have larger batteries and need a higher power level to complete
3 their charging cycle off-peak. Although long-duration DC is at power levels higher than
4 the typical L2, the off-peak load shapes being incentivized mirror those of the other
5 off-peak programs as the duration of charging needed via the DC charger is still four hours
6 or more. Finally, fleets also benefit their entire communities given their high-mileage use
7 and corresponding reductions in local pollution (noise and environmental).

8 In sum, the residential, public and fleet programs form a TEP portfolio strategy to
9 both (1) optimize the grid to benefit all customers, and (2) aid EV adoption by creating
10 charging confidence via strategically located infrastructure and equitable access to
11 charging. Given the data the Company has reported to the Commission,⁶ the TEPs continue
12 to serve the majority of managed charging scenarios, aid with equitable access to charging
13 infrastructure, and achieve the intended results. The Company believes the data strongly
14 supports continuation of the TEP programs.

15 **Q. Are TOU rates enough to optimize off-peak charging without TEP programs?**

16 A. Absolutely not. It continues to be the case that a negligible number of EVs enroll in the
17 Company's TOU rate without engagement. For example, in late 2023 the Company's AMI
18 data analysis showed just 493 of the 30,380 EVs enrolled in Rate 1050 (Nighttime Savers)
19 without TEP rebate or incentive engagement, which equates to a mere 1.6% of EV
20 customers. Again, in late 2024, advanced metering infrastructure ("AMI") data analysis

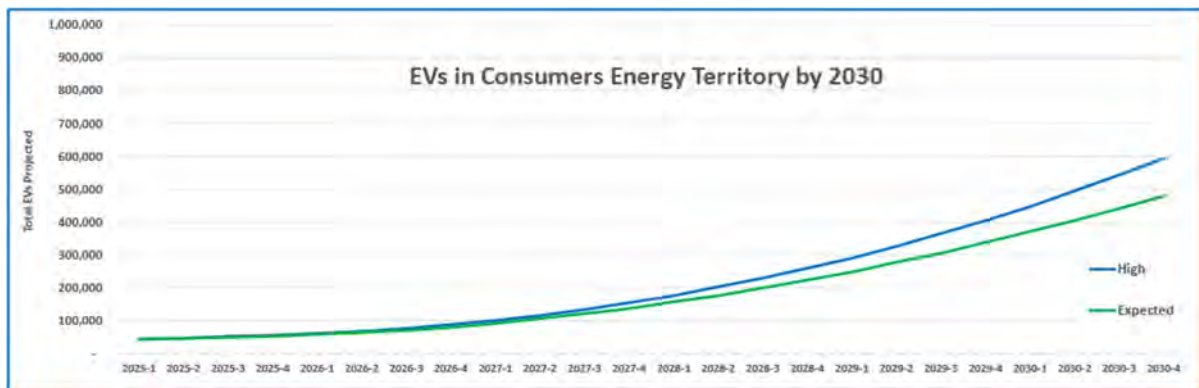
⁶ See 2024 TEP Report, at [0688y00000EFQgtAAH](#); see also 2023 PowerMIDrive and PowerMIFleet Annual Reports, at [0688y000008L9UaAAK](#) and [0688y000008KyQSAA0](#). The original TEP strategy from 2022 was provided in [0688y000002IGMIAAM](#). Finally, additional reports from the pilot phases (2022-2020) leading to the TEP are also available at [0688y000003NM62AAG](#), [068t000000NieAVAAZ](#), and [068t000000D3t95AAB](#). All of these regulatory filings show the Company's consistent focus on optimizing the grid and increasing charging infrastructure via strategic locations to benefit customers.

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indicated just 526 of 39,950 EVs enrolled in Rate 1050 without TEP program engagement, which is 1.3% of EV customers. The data is incredibly clear and irrefutable. Relying on TOU rates alone is highly ineffectual for EV load management. TEP programming must continue to optimize EV load.

Q. Are EV adoption and load growth projections continuing to materialize similar to the projections provided in prior filings?

A. Yes. EV load growth has been at or above the “500K EV” by 2030 EV scenario utilized in the 2021 Integrated Resource Plan (Case No. U-21090), annual TEP related reports, and prior electric rate cases. While the Company continues to prepare the TEPs to optimize load for one million EVs by 2030 in support of the State’s policy goals, which strongly support EV adoption and Michigan’s automotive manufacturing economic strength, EVs on the road are trending slightly lower than prior projections. In 2023, an outside source projected there would be 630,000 EVs on the road by 2030, and in 2021, the Company projected there would be 500,000 EVs by 2030.



The latest data from the Michigan Secretary of State also indicates that a range closer to 470,000 to 600,000 EVs by 2030 may be more likely in the Company’s territory. Whatever the correct forecast, there are more EVs on the road now than ever before and those EVs

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are driving more miles per year. Plus, more EV models are entering the market (SUVs, crossovers, and trucks) that are using more kWh per mile, and the Company's electric territory continues to be a destination for many EVs that reside outside of our electric territory (e.g., the greater Chicago, Detroit, and Toledo metros). Furthermore, our electric territory is the last opportunity to charge before traveling into the Upper Peninsula. Thus, total EV load growth, which is what truly matters for margin analysis and TEP program funding, remains solidly on track as shown in Exhibit A-165 (JAM-3) (see "Cost Benefit Analysis" tab, line 22).

Q. Please describe the specific TEP enhancements proposed to improve customer experience and benefits.

A. To be clear, the Company continues to implement the TEP program enhancements approved in Case No. U-21585, is maintaining the PowerMIDrive Residential program as approved in Case No. U-21224, is maintaining the PowerMIDrive Public Charging and PowerMIFleet programs as approved in Case No. U-21389, and is completing the pilot funds dedicated to customer projects in progress per approvals in Case Nos. U-20134, U-20697, and U-21224. No increases to the TEPs budget previously approved are proposed, and no changes are being made to the core program strategies to optimize off-peak charging from these recent permanent program approvals by the MPSC.

The proposed TEP enhancements are:

- (1) The allowance of the weatherized and EV-rated National Electric Manufacturers Association ("NEMA") 14-50 outlets across all L2 rebate categories and NEMA 5-20⁷ outlets across all long-duration L1 rebate categories. Given that many new EVs come with, and existing EV drivers utilize, a portable charger, focusing a project on the outlet can simplify installations and reduce costs for host sites. In particular, multifamily locations

⁷ NEMA 14-50 and NEMA 5-20 are standardized outlet designs commonly utilized for EV charging. Many L2 utilize a NEMA 14-50 plug for charging up to 9.6 kW, and many L1 utilize a NEMA 5-20 plug for charging up to 1.8 kW.

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have expressed interest in bring-your-own-cord (“BYOC”) solutions given desires to reduce costs and maintenance. Presently only community charging host sites can utilize outlets as a BYOC option, and the Company believes that it is a useful option across the board to reduce infrastructure costs.

(2) The continuation of Direct Current Fast Charging (“DCFC”) rebates on a time-limited and selective basis. The Company continues to believe that DCFC infrastructure incentives are needed to better enable EV travel and to encourage EV adoption. The Company also recognizes feedback from the MPSC Staff that such incentives should work to create a skeleton network, not be a permanent program, and recognize the 30D tax credit impacts.⁸ Thus we are modifying our fast-charging rebate proposal as follows:

a. The Company proposes a fast-charging rebate of up to \$50,000 per 150 kW DCFC port. The median and average costs of a 150 kW DCFC construction project range between approximately \$200,000 and \$237,000.⁹ The 30D tax credit is available for some, but not all, locations in the Company’s electric service territory¹⁰ and may provide a 30% tax credit for the project costs.¹¹ Thus, it is possible that the cost of a 150 kW DCFC project could be reduced to near \$140,000 to \$166,000 via the 30D tax credit, and a rebate of up to \$50,000 is approximately 1/3rd of the remaining cost, consistent with the original PowerMIDrive pilot approval that collaborated with Charge Up Michigan funds (Charge Up Michigan funds are no longer available, but the 30D tax credit may be available for some locations).

b. The DCFC rebates will only be available for communities that do not have at least four 150 kW DCFC ports across two or more different host sites. The four 150 kW ports per community is proposed as a cutoff because that mirrors the Federal minimum (i.e., skeleton) infrastructure per NEVI Standards and Requirements. See 23 CFR § 680.106(b). However, if those four ports are not spread over two or more different host sites in a community, then competition is limited, and thus an additional site will help keep pricing reasonable. Anecdotally, the Company has noticed that DCFC charging prices come down when a second host-site opens in an area. Thus, these criteria will steer rebate eligibility into communities that do not have fast-charging infrastructure and avoid subsidizing additional builds in urban areas that already have infrastructure.

⁸ See MPSC Case No. U-21585, Staff’s Reply Brief, pages 26-28, at [068cs00000Rc1jfAAB](#).

⁹ See 2024 TEP Report, pages 28 and 29, Figures 5 and 6, at [0688y00000EFQgtAAH](#) (Median construction costs of \$168,654 and make-ready costs of \$30,608 total \$199,262, while average construction costs of \$191,239 and make-ready costs of \$45,509 total \$236,748).

¹⁰ See the [30C Tax Credit Eligibility Locator](#) for a map of eligible locations. Some areas were only eligible in the past or will drop off in future years.

¹¹ United States Department of Energy, [Alternative Fuels Data Center: Alternative Fuel Infrastructure Tax Credit](#) (last visited April 28, 2025).

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- 1 c. The DCFC rebate application will only be available for two-years after
2 approval by the Commission. Thus, the fast-charging rebate program
3 proposed is not a permanent offering. However, please note that host sites
4 will be awarded their rebate after construction is complete, which will take
5 longer than the two-year window for rebate applications. Nonetheless, if
6 approved by the Commission, the limited DCFC rebate offering will be
7 contained within the TEP budget already projected and approved, and the
8 Company may close applications if the TEP budget is at risk of being
9 exceeded.
- 10 d. The Company will review rebates as they are received, thereby encouraging
11 expedited development of the skeleton network, but retains the right to
12 reject applications that do not offer quality customer experience. Given the
13 competitive nature instilled by the limited TEP budget, and the proposed
14 time and location restrictions for applications, the Company proposes the
15 following criteria to guide DCFC rebate host site selection and aid EV
16 adoption by improving the customer experience:
- 17 1. The host site should offer 24-7 charging and amenities, such as
18 restrooms, snacks, and meal opportunities for an average dwell time of
19 approximately 30 minutes. If such amenities are not 24-7, then
20 preference will be given to sites with longer operating hours and a
21 greater number of such amenities at or adjacent to the site. In no case
22 shall sites be allowed that do not offer 24-7 charging or that have no
23 public amenities. Furthermore, chargers and companies that cannot
24 maintain the existing DCFC performance requirement of 97% uptime
25 may also be excluded from future rebates if good faith efforts to restore
26 uptime cannot be demonstrated.
- 27 2. The host site should install the fast chargers within view of the road and
28 with pricing signage. Drivers need to see and be able to find fast
29 charging infrastructure. Preference will be given to such sites over those
30 that are at the far edge of a parking lot or hidden to the side or behind a
31 building or other visual obstacle.
- 32 3. The host site should utilize fast charging dispensers that can be activated
33 with a credit card or phone tap to pay instead of a specific app. The use
34 of multiple apps can be confusing, is a barrier to adoption, and also
35 slows down throughput at a site if a customer does not already have the
36 app installed and activated. Preference will be given to host sites that
37 replicate the experience of “pay at the pump” that many consumers are
38 used to.
- 39 4. The host site must have adequate security lighting and preferably a
40 canopy to protect from the weather. Drivers need to feel safe while
41 charging at night, and fast charging equipment is less likely to be
42 damaged by vandalism or exposure to the elements at such sites. Thus,

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1 preference will be given to host sites that offer good lighting and a
2 canopy.

3 5. The host site should use traffic flow designs to accommodate the
4 multiple charge port locations of various EV models, larger EVs, and
5 EVs pulling trailers. Preference will be given to sites that utilize
6 pull-through or other layouts that maximize access for different EV
7 types and sizes.

8 6. More traffic lanes, more ports. While more remote communities on
9 two-lane highways still greatly benefit from the addition of two 150 kW
10 fast charging ports at a host-site, locations near four-lane highways or
11 that experience high seasonal tourist inflows would benefit from more
12 ports. Thus, all host sites must offer at least two 150 kW DCFC ports,
13 and preference will be given to sites with more fast-charging
14 infrastructure, to increase charging confidence by EV drivers.
15 However, no more than four rebates will be offered per host-site in any
16 case.

17 In sum, the Company believes that the above enhancements will reduce
18 construction costs for the existing L2 and L1 program rebate categories, and temporarily
19 expand rebate offerings to help create a skeleton network of quality fast-charging sites in
20 areas that are still underserved via a time and budget limited competitive process.

21 **Q. Does the continued growth of EV adoption impact the testimony of another Company**
22 **witness that you wish to support?**

23 A. Yes. While many TEP programs focus on relatively low-power and longer-duration
24 charging to minimize grid impacts, and are successfully optimizing the load from those
25 participants, the Company anticipates that new service requests for DCFCs, both public
26 and for fleets, will grow dramatically in larger population centers. Thus, I support
27 Company witness Jennifer M. Partlan's request to proactively prepare for new and
28 expanded DCFC and larger fleet locations, especially in urban and interstate locations
29 where large developments are already occurring.

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1 To gain perspective on the magnitude of the challenge, we must first recognize that
2 many utilities are reporting that transformers supporting larger load sites (i.e., 500 kVA
3 and greater) can have lead times of 18 to 24 months or longer. This means that waiting
4 until a request for new or modified service for a fast-charging site or new fleet depot to
5 place an order for these transformers and related equipment will bottleneck EV adoption.

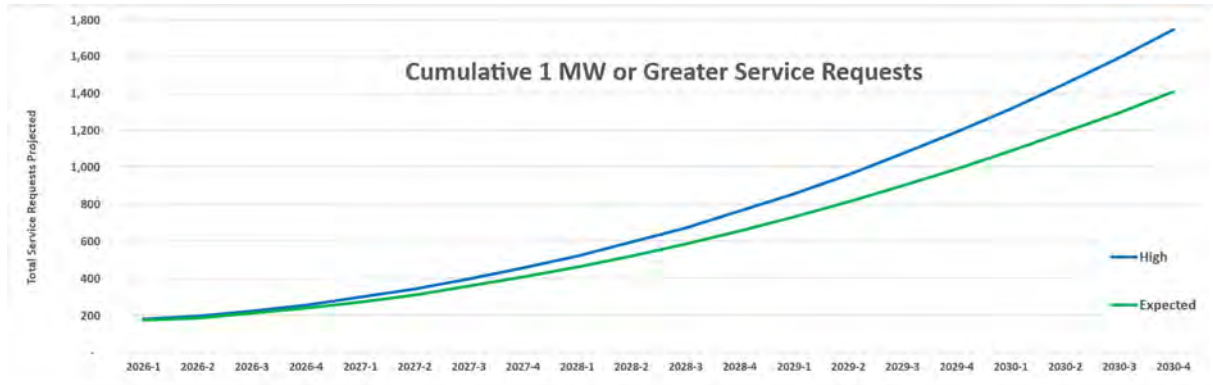
6 Looking at trends in DCFC development, new or expanded fast charging sites near
7 urban areas are larger and higher power, in addition to being installed at an increasing
8 frequency. For example, market data indicates that one fast charger is constructed for
9 approximately every 85 EVs on the road. Furthermore, developers are considering
10 additional capacity for holidays and cold weather impacts. More fast-charging sites are
11 also being installed with at least four chargers each of 250 kW or higher ratings, and thus
12 potentially drawing up to 1 MW at maximum output. The reason for this is the capabilities
13 of new EVs can often reach higher charging inputs, and customers prefer to choose a
14 fast-charging destination with multiple chargers and higher power outputs to avoid the risk
15 of queuing or impacts from a plug being down for maintenance.

16 Thus, many urban fast-charging sites are now trending toward sets of 8-12 fast
17 chargers, and we have learned of potential plans for 40 or more chargers along interstate
18 travel corridors. Furthermore, delivery fleets may desire to add hundreds of new EVs per
19 year as their current vehicles age out, and even with L2 charging this can result in large
20 load additions given the scale. These are very important trends to prepare for given
21 continued EV adoption and ensuring Michigan businesses and residents are timely served.

22 As a planning estimate, utilizing the ratio of one 250 kW fast charger per every
23 85 EVs, and growth rates trending between 470,000 and 600,000 EVs by 2030, the

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Company projects that approximately 1,400 to 1,700 EV service requests of 1 MW or greater could occur by 2030. With the near two-year timeframe to design a new service, procure and install make ready equipment, and energize a site, it is prudent to act now in preparation for forthcoming EV service requests.



Q. In the Company's Case No. U-21585 the Commission ordered the Company to provide updates on approved enhancements and any lessons learned in the Company's next Electric Rate case and PowerMIDrive and PowerMIFleet annual report, as recommended by the Staff. How is this being addressed?

A. The Company will be filing the next annual TEP report in Case No. U-21389 before July 1, 2025. The Company incorporates the report by reference, and I plan to sponsor it as an exhibit through revised direct testimony or rebuttal testimony as appropriate.

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)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

JENNIFER M. PARTLAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

JENNIFER M. PARTLAN
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1 **Q. Please state your name and business address.**

2 A. My name is Jennifer M. Partlan, and my business address is 1945 West Parnall Road,
3 Jackson, Michigan, 49201.

4 **Q. By whom are you employed?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

6 **Q. What is your position with Consumers Energy?**

7 A. I am currently Director of Low Voltage Distribution (“LVD”) System Planning.

8 **Q. What are your responsibilities as Director of LVD System Planning?**

9 A. My responsibilities as Director of LVD System Planning include oversight of activities
10 associated with planning for the Company’s low voltage electric overhead and
11 underground assets, as well as the Company’s streetlight assets.

12 **Q. What is your formal educational experience?**

13 A. I earned a Bachelor of Science degree in Electrical Engineering from Oakland University
14 in 2000. I earned a Master of Science degree in Engineering Management from University
15 of Michigan – Dearborn in 2005.

16 **Q. Please describe your work experience.**

17 A. I began my career with Jacobs Engineering in 2000 as an Instrumentation and Controls
18 Engineer, designing, programming, and commissioning equipment for test cell facilities
19 for automotive companies. In 2008 I started work at General Dynamics in the software lab
20 developing and testing software for military vehicles. In 2010, I worked at General Motors
21 in the transmission testing lab as a test engineer until I started at Consumers Energy in 2011
22 in the Tools and Work Methods team as the Electrical Team Lead. My duties included
23 working with the team that conducted tool demonstrations, updated work methods

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processes, and conducted site visits. From 2013 to 2018 I worked in the Substation Construction department as an Electric Construction Supervisor, working as the project manager for contractors conducting upgrade or modifications to substations or building Consumers Energy substations. I started in the LVD Planning department in 2018 as the Engineering Manager over the Grand Rapids Zone. My team monitored and proposed projects for the LVD lines in relation to capacity, reliability, and managing customer concerns and repetitive outages. In March 2025, I assumed my present position as Director of LVD System Planning.

Q. What is the purpose of your direct testimony in this proceeding?

A. As introduced by Company witness Michael P. Kelly, the purpose of my direct testimony is to explain the Company's projected capital costs in the electric LVD lines system. I will explain the purpose of this spending and the corresponding benefits. The testimony will describe the LVD work and associated costs for the New Business, Demand Failures, Asset Relocations, Reliability, and Capacity programs with a subsection for each LVD lines subprogram.

Q. Please explain the historical, bridge, and test year periods.

A. The historical year is 2024. The bridge period consists of the 16 months ending April 30, 2026. The test year is the 12 months ending April 30, 2027.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-166 (JMP-1) Bridge Period LVD Project List;

Exhibit A-167 (JMP-2) Test Year LVD Project List;

Exhibit A-168 (JMP-3) Conservation Voltage Reduction Measurement and Verification Independent Assessment; and

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Exhibit A-169 (JMP-4)

Summary of 2023 and 2024 LVD Repetitive
Outages Investment.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes, except that Exhibit A-168 (JMP-3) is an independent assessment prepared by a third party.

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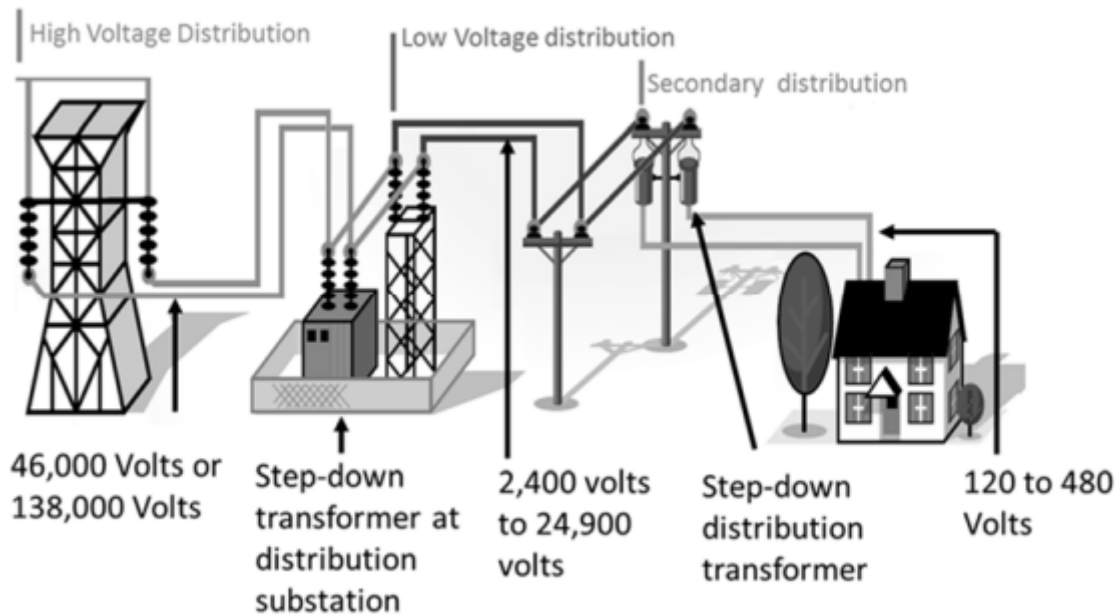
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LVD SYSTEM OVERVIEW

Q. Please provide an overview of the Company's electric distribution system.

A. As discussed by Company witness Kelly, the Company's electric distribution system is comprised of the high voltage distribution ("HVD"), LVD, and Metro systems. The HVD and LVD systems are shown below in Figure 1. My testimony is concerned primarily with LVD lines.

FIGURE 1
HIGH VOLTAGE AND LOW VOLTAGE DISTRIBUTION SYSTEM OVERVIEW



Q. Please provide an overview of the LVD system.

A. The LVD system is comprised of over 111,304 total miles of lines, made up of approximately 51,736 miles of primary overhead, 9,885 miles of primary underground, 31,209 miles of secondary overhead, and 18,474 miles of secondary underground. The LVD system consists of 13 different primary voltages between 2.4 kV and 24.9 kV (grounded-wye and delta). The number and range of primary voltages differ because the Company acquired several distribution systems from smaller distribution companies over

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1 its history. LVD primary voltage is then further stepped down at the distribution pole-top
2 or padmount transformer to a secondary voltage, serving businesses and residences at
3 voltages between 120 Volts and 480 Volts. More than 2,000 LVD circuits serve the
4 Company's approximately 1.9 million electric customers, where a circuit is defined as a
5 combination of electrical devices and hardware that are connected and emanate from an
6 LVD substation to deliver electrical energy to customers, operating at a defined nominal
7 voltage.

8 **Q. What challenges are faced by the LVD system?**

9 A. Broadly speaking, the LVD system is expansive and subject to the greatest threat from
10 common outage causes like vegetation, severe weather, equipment failure, unexpected load
11 increases, and third-party damage. The LVD system is largely a radial system that is not
12 capable of continuing service to customers during outages. Even with advances in
13 distribution automation, the LVD system remains configured such that every outage will
14 interrupt service to a number of customers, though the Company's recent efforts in
15 automation and additional fusing have reduced the number of customers impacted by
16 individual outages.

17 **Q. Does the Company have a strategy for addressing these challenges to the LVD**
18 **system?**

19 A. Yes. The Company's strategy has been provided in detail in the 2023 Reliability Roadmap,
20 also known as the *Electric Distribution Infrastructure Investment Plan* ("2023 EDIIP"),
21 that was filed in Case No. U-20147 on September 27, 2023, an amended version of which
22 is included in this case as Exhibit A-129 (MPK-19). Company witness Kelly provides
23 direct testimony explaining the Reliability Roadmap. In my direct testimony, I will explain

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how the Company is investing in the LVD system to provide needed reliability and resiliency of electric service to customers, and how these investments relate to the plan outlined in the Reliability Roadmap.

LVD PROGRAMS WITH CAPITAL SPENDING

Q. How does the Company classify its LVD capital investments?

A. As discussed by Company witness Kelly, the Company makes capital investments under two broad classifications, *unplanned* and *planned*.

- Unplanned investments include the New Business, Demand Failures, and Asset Relocations programs, and the LVD New Business Capacity subprogram; and
- Planned investments include the Reliability program and the remainder of the Capacity program.

Q. Please summarize the LVD capital expenditure plan in this filing.

A. In this filing, the Company is projecting to spend \$1,055,533,000 in capital projects on the LVD system in the bridge period, and \$1,086,679 in the test year. Note that the projected investment level for the bridge period is reflective of a 16-month period; on an annualized basis, this would translate to \$791,650,000 in annual investment. This investment plan is summarized by the capital programs shown in Figure 2 below.

FIGURE 2
LVD CAPITAL EXPENDITURES BY PROGRAM (\$000)

Program	2024 Actuals	Bridge Period	Test Year
New Business	\$239,005	\$396,010	\$337,982
Demand Failures	\$199,432	\$231,185	\$166,120
Asset Relocations	\$51,502	\$97,911	\$79,090
Reliability	\$89,384	\$248,078	\$406,130
Capacity	\$45,101	\$72,347	\$89,110
Electric Other	\$7,773	\$10,001	\$8,248
Total	\$632,197	\$1,055,533	\$1,086,679

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1 **Q. How has the level of investment in the LVD system been impacted by the Reliability**
2 **Roadmap?**

3 A. The Reliability Roadmap did not make a meaningful impact on LVD spending in the New
4 Business, Demand Failures, or Asset Relocations programs. LVD spending in those
5 programs is projected in this case based on relevant data and recent trends as described
6 later in this testimony.

7 The Reliability Roadmap has led the Company to project increased investment
8 levels in key LVD subprograms in the Reliability and Capacity programs, compared to
9 pre-Reliability Roadmap historical levels. I will address the connection between those
10 LVD subprograms throughout my direct testimony in their respective sections, but I will
11 note here that the largest impacts from the Reliability Roadmap regarding lines are to the
12 LVD Lines Reliability, Resiliency, and LVD Lines Capacity subprograms.

13 **Q. What specific LVD lines projects does the Company expect to invest in during the**
14 **bridge period and test year?**

15 A. Specific projects are identified in Exhibits A-166 (JMP-1) and A-167 (JMP-2). The
16 exhibits include projects identified with scope, cost, location, benefit type, and benefits.
17 The two quantitative benefit types are:

- 18 • Customer outage minutes avoided (also referred to as minute interruptions and
19 abbreviated “CMI”): Product of the number of customers that experience an
20 extended outage of electrical service and the duration of outage measured in
21 minutes.
- 22 • Customers impacted: Number of customers served by a project. In the case of
23 commercial customers, the customers impacted are treated as “1.”

24 Note that not all projects have quantitative benefits. Some projects may be completed for
25 regulatory compliance, based on the Company’s obligation to serve customers, or other
26 reasons. Company witness Kelly provides more details about how the quantitative benefits

1 are calculated. Throughout my direct testimony, I will explain more about the specific
2 benefits of each investment sub-program.

3 **New Business Program**

4 **Q. What portion of the New Business Program will your testimony discuss?**

5 A. The New Business Program includes the capital costs of connecting new commercial,
6 industrial, and residential customers to the Company's distribution grid. Company witness
7 Kelly introduces and further discusses this program. My testimony will focus on the LVD
8 subprograms:

9 (i) LVD Lines New Business; and

10 (ii) LVD Transformers.

11 Projected spending and benefits are explained in detail in the subprogram section
12 below. LVD Transformers are discussed in a separate section later in my direct testimony.

13 **LVD Lines New Business**

14 **Q. Please explain what capital projects, activities, and other types of work will be enabled
15 by expenditures in the LVD Lines New Business subprogram.**

16 A. The LVD Lines New Business subprogram includes the capital cost of serving new
17 commercial, industrial, and residential customers. These costs include the necessary
18 overhead and/or underground distribution extensions and enhancements required to
19 complete new service connections, including the cost for new plats and developments.

20 Projects within this subprogram are initiated by customers whom the Company
21 must serve pursuant to tariff requirements. In general, the Company does not have
22 advanced knowledge of LVD Lines New Business projects in the preceding year, as the
23 projects are generally completed within the same year that they are requested. The

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1 projections for installed units and investment are based upon historical activity with
2 adjustments for anticipated variations in business, with input from external data sources,
3 covered in more detail later in my testimony.

4 **Q. What benefits will customers realize through the Company completing work in the**
5 **LVD Lines New Business subprogram?**

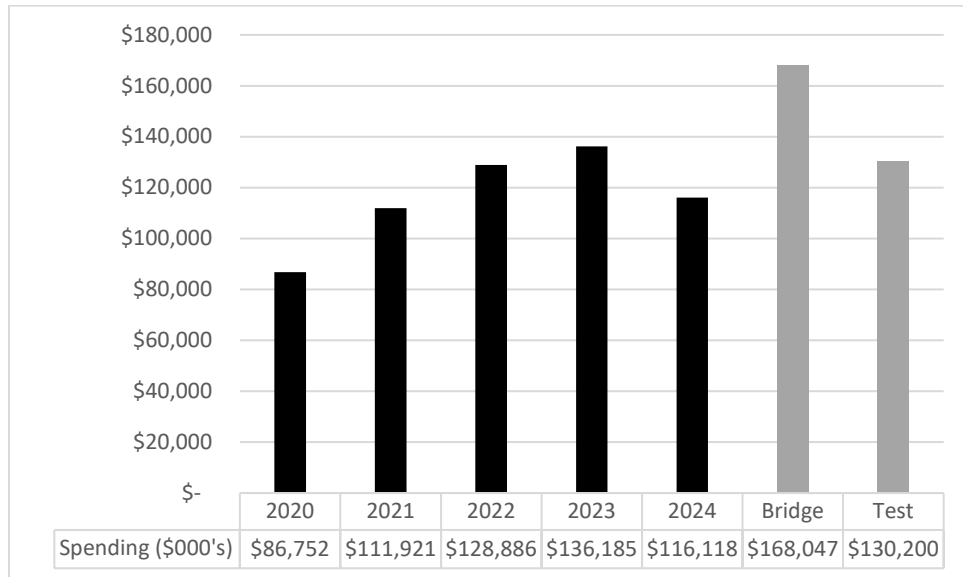
6 A. Fundamentally, new customers benefit because customers' homes, businesses, and other
7 facilities receive access to the grid and the electricity that it provides. This also supports
8 economic growth in Michigan by enabling new residential, commercial, and industrial
9 facilities to access electricity. The projected spending level will allow the Company to
10 provide a new service installation to every customer who requests it.

11 **Q. What is the Company's projected bridge period and test year spending levels, for**
12 **which it is requesting cost recovery, in the LVD Lines New Business subprogram?**

13 A. The Company is projecting LVD Lines New Business capital expenditures of
14 \$168,047,000 in the bridge period and \$130,200,000 in the test year, as shown in Exhibit
15 A-113 (MPK-3), line 1, columns (k) and (l). The Company's historical actual spending in
16 the LVD Lines New Business subprogram, along with the bridge period and test year
17 projections, are shown in Exhibit A-113 (MPK-3), line 1, and below in Figure 3.

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FIGURE 3
LVD LINES NEW BUSINESS SUBPROGRAM EXPENDITURES



Q. How did the Company develop its projected expenditures in this subprogram?

A. Projected expenditures for the LVD Lines New Business Program were based on the expected number of new service connections in the Company's service territory and the projected unit cost of new services.

Q. How does the Company project new service connections?

A. The Company has found that new service connections in its service territory typically track with the number of single-family home permits issued, as reported by the U.S. Census Bureau¹. Figure 4 below shows the relationship between the two data sets. The Company uses the historical number of new service connections as a foundation for its projections and consults forecasts of single-family housing permits from the Home Builders Association of Michigan ("HBAM") for additional information.

The U.S. Census Bureau data indicates that single family home construction in Michigan increased by 5% in 2024 compared to 2023. The total number of single-family

¹ US Census Data: <https://www.census.gov/construction/bps/annual.html>

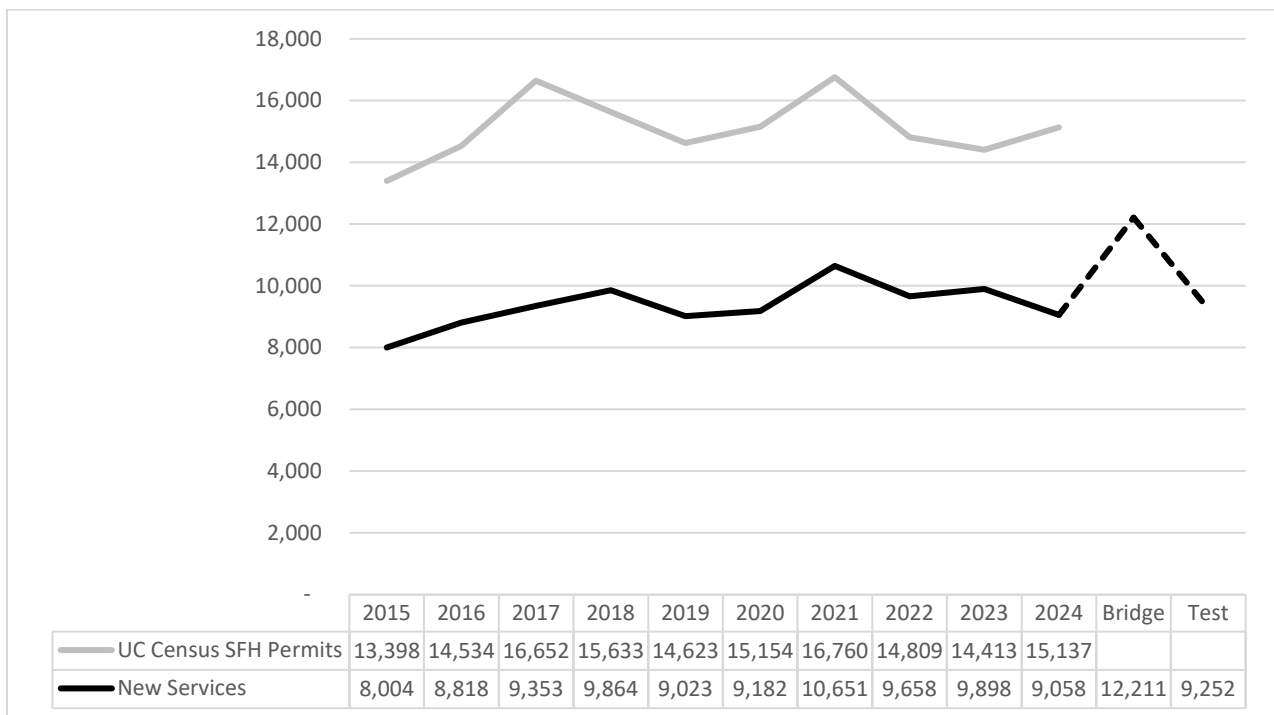
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housing permits issued in the state last year totaled 15,137 compared to the 14,413 permits that were issued in 2023². In January 2025, HBAM provided a preliminary forecast for 2025 that 15,728 single-family home permits would be issued, a 3.9% increase over 2024.³ HBAM's forecast supports a growth in Michigan single-family home construction in 2025, and the Company is projecting it will have more new service connections in 2025 and 2026 than in 2024.

Q. What is the Company's forecasted number of new service connections?

A. The Company is projecting 12,211 new service connections for the 16-month bridge period and 9,252 for the test year. Figure 4 below illustrates the historical and projected new service connections.

FIGURE 4
HISTORICAL AND FORECASTED NEW SERVICE CONNECTIONS



² U.S. Census data: <https://www.census.gov/construction/bps/statemonthly.html>

³ HBAM press release: <https://hbaofmichigan.com/assets/pdf/Forecast.Release.1.30.25.Final/>

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1 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
2 **subprogram?**

3 A. Yes, for the overall subprogram. The unit for this subprogram is projects, and the projects
4 undertaken are specifically tailored to the needs of the customer requesting the work. There
5 is a variance of costs among the different projects; however, because of the volume of
6 service connection units, an average unit cost can be used to develop the spend projections
7 for the overall subprogram.

8 **Q. How does the Company project the average cost of new service connections?**

9 A. The Company used its actual historical costs to inform future unit cost projections for new
10 service connections. While unit cost for this subprogram decreased from 2023 to 2024, the
11 Company anticipates unit cost increases for the bridge period and test year relative to the
12 2024 amount to account for inflation, increasing length of service lines, and increased
13 amount of underground services. Figure 5 below illustrates the historical and projected
14 unit cost for new service connections.

15 **Q. Is the Company proposing any electric service connection fees related to this**
16 **sub-program in the instant case?**

17 A. The Company is updating its residential and general service fees. The new fees are
18 addressed by Company witness Brittani A. Gray.

19 **Q. Does the Company expect the proposed changes in fees to affect the number of**
20 **overhead and underground services installed?**

21 A. Yes. Currently, 87% of the service installations are underground. Given the change in
22 service fees, the Company expects the percentage of underground services to increase to
23 99%. The 1% of overhead services is expected to remain for customers where an

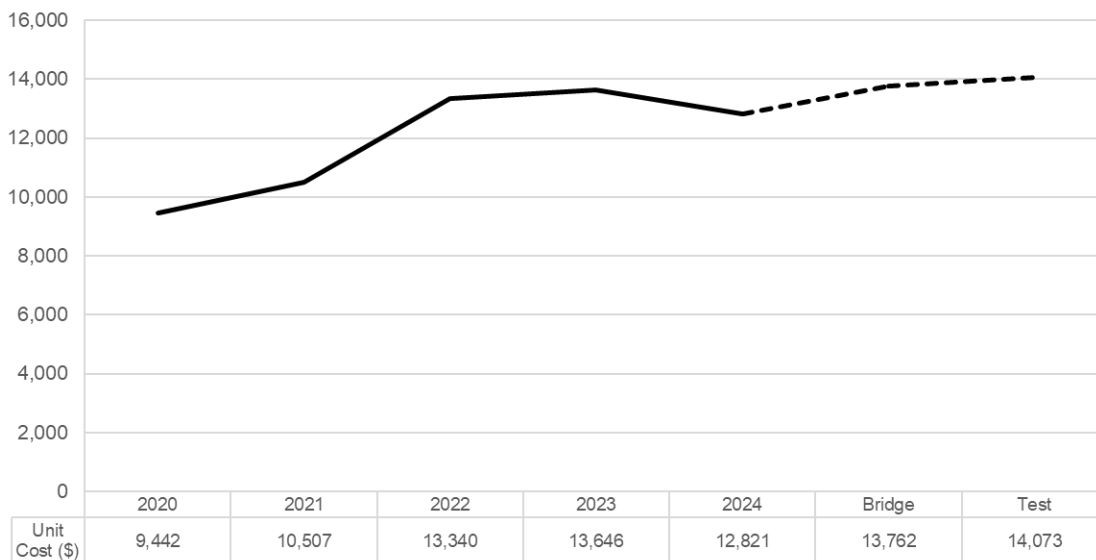
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underground service is not possible due to ground conditions such as wetlands, contaminated soil, etc.

Q. How will customers benefit from underground services?

A. Considering the exposure to weather and trees, storms that pass through the Company's service territory typically affect overhead services much more than underground services. For example, over the last two and a half years, overhead residential services are approximately 45 times more likely to fail than underground residential services. During storm restoration, the Company prioritizes restoration work that restores large numbers of customers or critical facilities, such as hospitals. Given the focus on reducing the time customers spend without power to meet the Commission's Service Quality and Reliability Standards, the restoration of residential services, which typically impacts only one customer, are often not completed until near the end of storm restoration work. With an underground service, customers are less likely to be subjected to a service-driven outage and the long duration of restoration associated with such an outage.

FIGURE 5
HISTORICAL AND FORECASTED UNIT COSTS FOR NEW SERVICE CONNECTIONS



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1 **Q. Why has the Company experienced increased unit costs in this subprogram in recent**
2 **years?**

3 A. In addition to inflation, the Company has seen increases in the average length of a new
4 service connection. The Company experienced an increase in unit cost in 2022 due
5 primarily to increased material and contractor costs; however, the Company has worked to
6 reduce its unit cost, resulting in a reduction for 2024.

7 **Q. How does the change in the customer service connection fees impact projected**
8 **spending in this sub-program?**

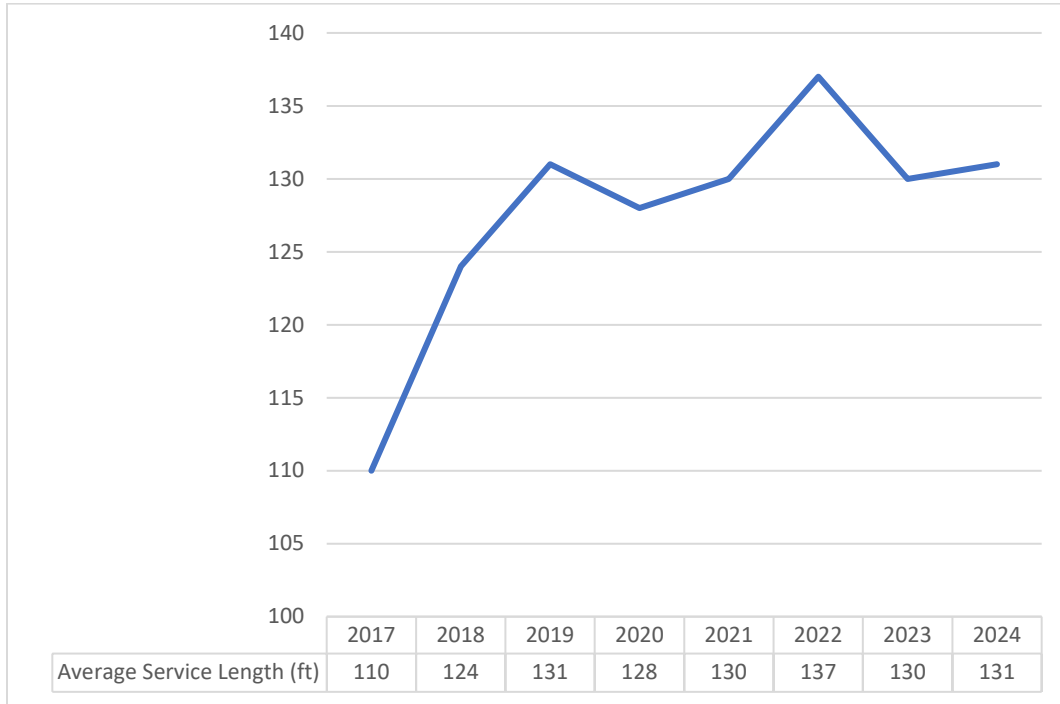
9 A. The increased fees are expected to save \$2 million in the capital requested for service
10 connections. This savings has already been accounted for in the Company's projections,
11 so there is no further new change to the projected spending.

12 **Q. Please describe the increases in average service length.**

13 A. Service length is influenced by the optimal route of the service on a customer's property
14 from the Company facilities to the customer's preferred location. The Company has had
15 an increase in average service from 110 feet in 2017 up to 131 feet in 2024, as shown in
16 Figure 6 below.

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FIGURE 6
HISTORICAL AVERAGE SERVICE LENGTH



Q. Are there unit cost differences between new services installed by contractors and those installed by Company employees?

A. Yes. In its final Order in Case No. U-21585, the Commission directed the Company to develop a comparison and present it in the instant case. The results of this analysis are shown in Figure 7 below.

FIGURE 7
*COMPARISON OF COMPANY VS. CONTRACTOR UNIT COSTS
FOR LVD LINES NEW BUSINESS, 2020-2024*

	2020	2021	2022	2023	2024
Company Units	5,383	5,976	6,601	8,923	8,061
Contractor Units	3,799	4,675	3,057	975	997
Company Unit Cost	\$9,314	\$9,298	\$11,334	\$12,002	\$11,987
Contractor Unit Cost	\$9,449	\$11,134	\$16,585	\$26,383	\$21,013

1 **Q. What is shown by this comparison?**

2 A. This comparison illustrates that, beginning in 2021 and especially in 2022, contractor costs
3 have increased more quickly than internal costs, although contractor costs decreased
4 significantly in 2024 following a contract renegotiation. Correspondingly, the Company
5 shifted much of the work in this sub-program to internal resources. However, it is
6 important for the Company to maintain some level of contracted work in this sub-program
7 because contractors provide a level of flexibility and scalability to allow the Company to
8 respond to the unplanned nature of this work. Contractors also ensure that Company
9 employees are able to work on other jobs, such as in the Reliability program.

10 **Demand Failures Program**

11 **Q. What portion of the Demand Failures Program will your testimony discuss?**

12 A. The purpose of the Demand Failures Program is to address issues related to customer
13 interruptions and failures of equipment on the distribution system. Company witness Kelly
14 introduces and further discusses this program. My testimony will focus on the LVD
15 subprograms:

- 16 (i) LVD Lines Demand Failures; and
17 (ii) LVD Metering.

18 Projected spending and benefits are explained in detail in the subprogram section below.
19 LVD Metering is discussed later in a separate section of my testimony.

LVD Lines Demand Failures

Q. Please explain what projects, activities, and other types of work the LVD Lines Demand Failures subprogram expenditures will enable.

A. The LVD Lines Demand Failures subprogram includes capital expenditures incurred during customer interruption restoration, or during the repair or replacement of LVD equipment due to unanticipated failure. The expenditures will enable the Company to respond to day-to-day equipment failures and perform storm restoration work that is capital in nature. Projects are not planned far in advance in this subprogram, because it is meant to quickly respond to equipment failures and customer interruptions that occur in real-time. The LVD Lines Demand Failures subprogram consists of two investment categories: Service Restoration Orders and Security Assessment Inspection Orders.

Q. What work is done in the Service Restoration Orders investment category?

A. Service Restoration Orders consist of work completed on an emergent basis to quickly restore customers who are without power for various reasons, such as following storms or equipment failures.

Q. What work is done in the Security Assessment Inspection Orders investment category?

A. Security Assessment Inspection Orders consist of projects created to fix issues identified in the Company's visual line inspections as discussed further below in my direct testimony on this sub-program.

Q. How does the Company identify and prioritize LVD Lines Demand Failures projects?

A. Once a failure or other damage to the system has been identified, either due to a customer interruption or due to a security assessment, the Company prioritizes its response by

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categorizing damage by severity, as either a Priority 1 (“P1”) or Priority 2 (“P2”), as shown in Figure 8 below.

FIGURE 8
LVD SECURITY ASSESSMENT HAZARD CODES

Code	Description
P1 - Public Safety	
P1A	Safety Code Violation
P1B	Unusual Public Hazard
P2 - Failures	
P2A	Floating Phase / Neutral
P2B	Broken / Cracked Cross-arm
P2C	Damaged / Cracked Cutout
P2D	Damaged / Cracked Insulators
P2E	Pole: Needing Immediate Replacement
P2F	Pin Pulling from or through Crossarm/Pole
P2G	Other Failed Structure or Equipment

Q. How does the Company respond to P1 and P2 failures?

A. P1 failures include problems that require immediate action to repair the damage. This includes threats to public safety, such as downed wires or exposed underground equipment. P1 failures are addressed within 24 hours.

Like P1 failures, P2 failures consist of equipment that has failed, but P2 failures are less urgent. For example, the Company may find an insulator that has detached from its pin, creating a clearance or public safety hazard. The line would remain energized but no longer in its safe operating condition.

At times, the Company may quickly address a P1 failure by reducing it to a P2 failure. For example, the Company may address exposed cables in a fiberglass pad by applying a temporary patch; the P1 emergency-level issue will have been fixed, but the pad is still failed and requires replacement. Typically, the Company works to respond to P2 failures within 60 calendar days. However, this time can extend beyond 60 days, such as

1 when the failed equipment has been bypassed and new equipment is on order for
2 replacement.

3 **Q. What approach does the Company use to identify failures on the overhead LVD**
4 **system?**

5 A. In early 2022, the Company recognized that deterioration was contributing to failures of
6 overhead structures and equipment, increasing System Average Interruption Duration
7 Index (“SAIDI”). Replacement of those failures on an emergent basis cost more than
8 preemptive identification. Accordingly, the Company enhanced its focused assessment
9 program of the LVD overhead system in 2022. The inspections now identify only P1 or
10 P2 failures (note that these are actual failures, in that equipment is already broken, even if
11 customers have not yet been interrupted). This visual line assessment and maintenance
12 approach is supported by Electric Power Research Institute (“EPRI”). Their 2015 technical
13 report, *Distribution Grid Resiliency: Overhead Structures*,⁴ page 9-13, states: “Utility field
14 tests showed failures far from tree impacts, particularly at weak equipment. Line inspectors
15 can spot some of these weaknesses, particularly cracks in pole tops and cracked or rotten
16 crossarms. Identifying and fixing these can prevent breakage and reduce overall restoration
17 time.” EPRI is describing the items that are contained within the Company’s P1 and P2
18 failure categories.

19 The assessments completed by the Company also identified opportunities to add
20 high-value lateral fusing, and locations where vegetation was an emergent risk of causing
21 an outage. The lateral fusing additions are discussed in the LVD Lines Reliability section
22 of my testimony. The vegetation threats were addressed by the Line Clearing team.

⁴ *Distribution Grid Resiliency: Overhead Structures*, <https://www.epri.com/research/products/000000003002006780>

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1 **Q. Please summarize the recent assessments.**

2 A. The Company completed an assessment of 100% of its LVD overhead system in 2022 and
3 2023. The P1 and P2 failures identified in these inspections were corrected as part of this
4 subprogram. Based on the findings and benefits of these assessments, the Company began
5 assessing 50% of its overhead LVD system annually starting in 2024.

6 **Q. How many failures were identified through these focused security assessments?**

7 A. In 2022, the Company identified 6,814 P1 and P2 failures. In 2023, 10,738 P1 and P2
8 failures were identified. In 2024, the Company identified 10,965 P1 and P2 failures. On
9 average the security assessments have identified one failure for every three miles of line.

10 **Q. Are security assessments the only investment needed to improve SAIDI?**

11 A. No. While correcting failures identified during security assessments mitigates customer
12 outages related to deterioration and other defects, this activity alone is insufficient to
13 improve SAIDI overall. Correction of failures does not enhance the overall system.
14 Rather, it simply corrects the defect at a single point on the system. For example, choosing
15 to replace only one tire on a car when it goes flat would result in four disruptions to travel
16 over time, whereas replacing all four tires upon observing the tread on any one tire is worn
17 away would mitigate travel disruptions due to failed tires. Only focusing on security
18 assessments would be analogous to only replacing the single tire that goes flat; making
19 other proactive reliability assessments is analogous to replacing all four tires at once.
20 Therefore, even when security assessment work is completed, the Company still must make
21 investments in other sub-programs to improve SAIDI, particularly in the Reliability
22 sub-programs discussed later in my direct testimony.

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1 **Q. What are some examples of failures found in these focused security assessments?**

2 A. The pictures below include examples of P2 failures identified during the assessments in
3 2024. In the left photo of Figure 9, the lightning arrestor is damaged due to a lightning
4 strike and needs to be replaced. In the right photo of Figure 9, decay and damage at the
5 ground line of a wood pole has greatly undermined the strength of the pole. The left photo
6 of Figure 10 depicts a severely damaged pole, mostly caused by a third party. The right
7 photo of Figure 10 is of a cracked cutout that has fallen off its mount and is being supported
8 by the conductor.

FIGURE 9
LVD P2 FAILURES IDENTIFIED THROUGH SECURITY ASSESSMENTS



FIGURE 10
LVD P2 FAILURES IDENTIFIED THROUGH SECURITY ASSESSMENTS



1 **Q. When the Company determines that service restoration activity is required, what**
2 **types of projects are considered?**

3 **A.** The Company performs the following types of service restoration capital work:

- 4 • Failed Underground Cable – When a failure occurs on an underground cable,
5 the Company identifies and fixes the fault immediately to restore service to
6 customers. If the underground cable is looped (has feeds from multiple
7 directions), the fault is isolated and service to customers is restored until the
8 permanent restoration is completed within this program;
- 9 • Failed Distribution Transformer – These failures are addressed immediately
10 and could warrant further evaluation to determine if the transformer was
11 adequately sized for the load, which, in some cases, leads to replacement of the
12 existing transformer with a larger one;
- 13 • Car-Pole Accident – When car-pole accidents result in damage to poles, the
14 Company immediately assigns an available crew to ensure safety of the area,
15 replace the pole, and restring or splice the conductor;
- 16 • Broken Cross-arm, Pin/Insulator, or Pole – When poles and other components
17 fail, electric service may be interrupted, or public safety might be affected
18 where the wire is left hanging below the required clearance or out of normal

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operating position. The Company will replace any broken equipment (i.e., a cracked cross-arm); and

- Failed Overhead Conductor – When overhead wires fail due to age, deterioration, weather, trees, etc., it typically causes a wire down, which can pose a major public safety hazard. The Company addresses these conditions immediately.

Q. What benefits will customers realize through the Company completing work in the LVD Lines Demand Failures subprogram?

A. This subprogram is essential for the restoration of service to customers for the Company to meet its obligation to serve. Absent investment in this category, customers would remain without electric service because this program funds the basic work necessary to restore electrical service following a failure. Proactive identification of P1 or P2 defects provides a reliability benefit to customers, by improving the condition of system equipment when failed components are replaced, and placing the system back into a normal operating condition, eliminating a likely outage in the future. EPRI also identified this work as a benefit that "...can prevent breakage and reduce overall restoration time." EPRI further noted no drawbacks or risks with this approach. The Company estimates, using its Advanced Distribution Management System ("ADMS") outage data, that the effort in 2022 to identify and remedy P1 and P2 defects reduced system SAIDI, excluding Major Event Days ("MEDs"), by 3.7 minutes through fewer customer outages. In 2023, this effort reduced system SAIDI, excluding MEDs, by 4.0 minutes through fewer customer outages, and in 2024 it was reduced by 6.2 minutes.

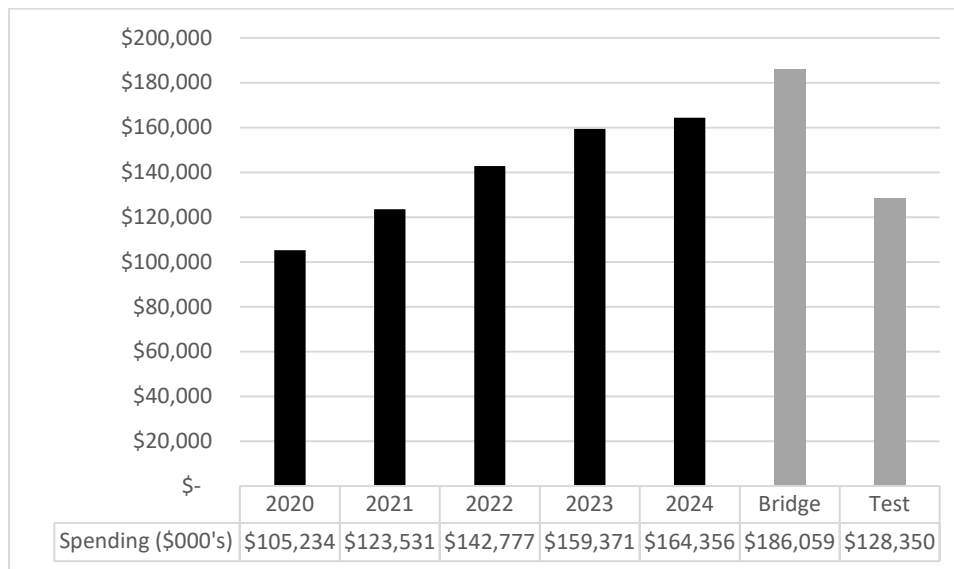
Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Lines Demand Failures subprogram?

A. The Company is projecting LVD Lines Demand Failures subprogram capital expenditures of \$186,059,000 for the bridge period, and \$128,350,000 for the test year, as shown in

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Exhibit A-113 (MPK-3), line 32, columns (k) and (l). The Company's historical actual spending in the LVD Lines Demand Failures subprogram, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 32, and below in Figure 11. Historical spending from 2020 to 2021 in LVD Lines Demand Failures also included the streetlight failure investment category.

FIGURE 11
LVD LINES DEMAND FAILURES SUBPROGRAM EXPENDITURES



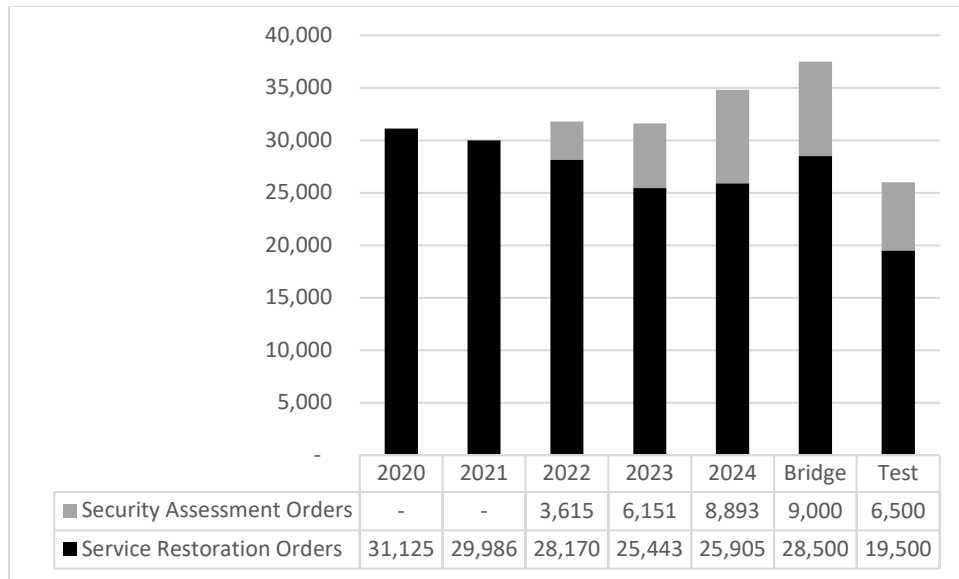
Q. How did the Company develop its projected expenditures in this subprogram?

A. The Company is projecting it will need to complete 37,500 total orders in the bridge period, consisting of 28,500 Service Restoration orders and 9,000 Security Assessment Inspection orders. Within the test period, the Company is projecting it will need to complete 26,000 total orders, consisting of 19,500 Service Restoration orders and 6,500 Security Assessment Inspection orders. The average unit cost for both periods for Service Restoration and Security Assessment orders is \$5,300 and \$3,900, respectively. The Company anticipates that its efforts to proactively identify P1 and P2 failures will mitigate the need for a higher number of orders as efforts better match the rate of system

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deterioration. The historical and projected number of orders is shown in Figure 12 below. However, the Company's electric distribution system continues to experience weather challenges, which may require an increased number of service restoration orders to be completed.

FIGURE 12
LVD LINES DEMAND FAILURES UNITS



Q. Please explain the year-over-year variation in spending in this subprogram.

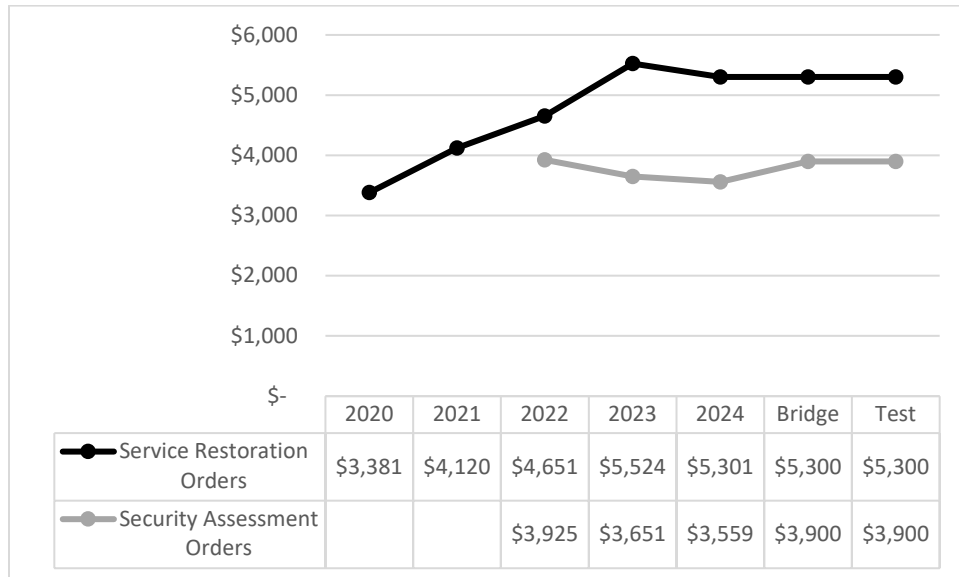
A. Spending increases in this subprogram over the past four years have primarily been attributed to unit cost. The four-year average number of orders completed was 31,100.

Q. What are the historical unit costs for the LVD Lines Demand Failures subprogram?

A. The historical and projected unit costs of service restoration orders are provided in Figure 13 below:

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FIGURE 13
LVD LINES DEMAND FAILURES UNIT COSTS



1 **Q. Please explain any variation in unit costs over time.**

2 A. Service restoration costs can vary due to variations in size and complexity of work orders.
3 The increase in failure unit costs can be attributed to increased material costs as noted in
4 the LVD Lines New Business section of my testimony. The costs of wire, cable, and poles
5 have increased in the last three years. Additionally, the Company's proactive approach to
6 address failures has increased the amount of materials used, and thus time spent, on each
7 of those repairs. For Service Restoration Orders, the Company is projecting the same unit
8 costs for this case (\$5,300 per order) that were used to project the costs approved by the
9 Commission in Case No. U-21585.

10 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
11 **subprogram?**

12 A. Yes. Unit costs can provide a generally reasonable expectation of the overall average
13 project cost within the LVD Lines Demand Failures subprogram. However, any individual

1 project in this subprogram can range from a few hundred dollars to replace pins and
2 insulators to as high as \$500,000 to replace failed underground cable and equipment.

3 **Asset Relocations Program**

4 **Q. What portion of the Asset Relocations Program will your testimony discuss?**

5 A. The Asset Relocations Program includes capital investments to relocate electric assets to
6 accommodate road, building, and other third-party construction projects, as well as internal
7 Company projects. Company witness Kelly introduces and further discusses this program.
8 My testimony will focus on the LVD Asset Relocations subprogram. Projected spending
9 and benefits are explained in detail in the subprogram section below.

10 **LVD Asset Relocations**

11 **Q. Please explain what projects, activities, and other types of work will be enabled by**
12 **expenditures in the LVD Asset Relocations subprogram.**

13 A. The LVD Asset Relocations subprogram responds to internal and external requests to
14 relocate LVD lines. This subprogram also includes “make-ready” work to prepare LVD
15 poles for third-party attachments; make-ready work can include physical relocation of a
16 pole, but it may also include work to strengthen a pole to allow it to support additional
17 weight. State and municipal agencies, private property owners, and other Consumers
18 Energy departments make requests for relocations; in addition, telecommunications
19 companies request make-ready work so they can attach phone and cable lines and cellular
20 equipment on poles. The subprogram includes any reimbursements from the requesting
21 party, which directly offset expenses incurred to perform the work. The annual subprogram
22 expenditures are based on the cost to relocate less the reimbursements received. Due to
23 the demand-based nature of this subprogram, the Company does not follow a specific

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1 planning cycle, and generally cannot plan relocation projects far in advance. Each request
2 contains different timelines and requirements based on the nature of the request, and the
3 Company constantly adjusts timing of projects to meet customer schedules. The Company
4 projects its spending levels based on historical activity, while also accounting for observed
5 trends, particularly related to economic activity.

6 **Q. When does the Company request reimbursement for a third-party initiated relocation**
7 **request?**

8 A. The Company seeks reimbursement for a third-party initiated relocation request anytime a
9 requesting party requests relocation of Company facilities where the Company has
10 existing, valid rights for the location of its facilities.

11 **Q. Does reimbursement match the cost of relocation?**

12 A. Reimbursement does not always match 100% with the cost of the relocation because the
13 reimbursement request is based on a design estimate. The actual construction costs may
14 come in higher than the design estimate due to unforeseen operational expenditures, such
15 as changes to field conditions, safety mitigation (i.e., traffic control), or other factors. In
16 addition, there may be times where it is in the customers' best interest to perform some
17 additional rehabilitation work to adjacent structures or equipment that would not be billed
18 to the requesting party.

19 **Q. How does the Company use information provided by a party requesting relocation?**

20 A. The Company studies the descriptions, maps, surveys, designs, and other documentation
21 provided by the requester, and combines that documentation with internal maps and field
22 measurements to determine what Company facilities, if any, require relocation and where
23 assets should be relocated.

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1 **Q. What actions does the Company take when relocation is required?**

2 A. For requests requiring significant relocation or changes to the LVD system, the Company
3 evaluates the proposed changes against a load flow analysis and reliability assessment to
4 determine if relocation will have an adverse effect on the system. If a proposed relocation
5 will negatively impact the reliability or capacity of the LVD system, changes would be
6 necessary. For example, a customer could request relocation of facilities to the edge of
7 their property line, but that move could put the facilities in dense vegetation, making the
8 line less accessible and requiring more line clearing. In that case, the Company would
9 work with the customer to find a better route that meets the customer's needs without
10 impeding reliability. On the other hand, if the relocation significantly changes the length
11 of conductor, it may create a capacity issue and the conductor would need to be upgraded
12 in size.

13 **Q. Please describe the types of projects that the Company includes in the LVD Lines**
14 **Relocation subprogram.**

15 A. The Company categorizes requests for relocation as:

- 16 (i) customer requested (government agencies or private property owners) and
17 requested by other departments within Consumers Energy;
18 (ii) relocation of LVD underbuild on HVD poles; or
19 (iii) attachment parties requesting make-ready work.

20 **Q. What is the nature of relocation requests made by government agencies?**

21 A. Government agency requested LVD relocations can fluctuate for many types of projects,
22 such as road and bridge widening or improvements, repairs to municipal facilities, and
23 streetlight and traffic signal modifications. Road and bridge widening, or improvement
24 projects, require the Company to move poles, wires, and other LVD equipment due to

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1 changes to the road location and grade, and to provide proper clearance for any large
2 equipment that the road construction contractors have on site. Large additions to civic
3 buildings can also lead to local governments asking the Company to relocate LVD assets
4 to accommodate those projects. Government agency timelines can vary widely based on
5 size and complexity.

6 **Q. What is the nature of relocation projects requested by private property owners?**

7 A. Private property owner requests vary widely based on the type of project and project
8 timeline. Property owners request LVD relocations for building additions, logistics,
9 landscaping, or other construction projects. Private landowners often request relocation of
10 overhead lines out to the road or underground, particularly to facilitate moving large farm
11 equipment. Residential customers often request relocation of LVD lines to facilitate
12 building an addition, pool, shed, barn or landscaping feature, such as a pond or berm.
13 Commercial customers often request relocation of poles from a parking lot or other area.

14 **Q. What is the nature of relocation requests generated within the Company?**

15 A. Relocation requests within the Company may come from the HVD Planning group, the
16 Substation Planning group, or the Metro Planning group, to facilitate projects planned by
17 their respective groups. Most of the requests within the Company consist of requests to
18 relocate LVD underbuild on HVD poles. LVD underbuild refers to LVD assets that are
19 attached to an HVD pole under the HVD lines. When an HVD pole is replaced, the LVD
20 components need to be rebuilt and the conductors need to be transferred to, or replaced on,
21 the new pole.

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1 **Q. What is the nature of relocation requests for make-ready work?**

2 A. Make-ready work is initiated through the Company's pole attachment permitting process
3 after an applicant, typically a communications company, requests to place new attachments
4 or modify existing attachments on Company poles. The scope of make-ready work for
5 each application is determined by field measurements and engineering analysis of existing
6 conditions with the applicant's proposed attachment characteristics, which is evaluated to
7 meet National Electric Safety Code ("NESC") requirements. Make-ready work can
8 include a range of construction activities, including but not limited to raising electric
9 conductors and equipment, adding or manipulating down guys, effectively grounding
10 streetlight brackets, raising or lowering existing communications attachments, and pole
11 replacements. In recent years, make-ready work has taken on increased importance due to
12 the rollout of government infrastructure programs designed to expand access to broadband
13 internet, particularly in rural areas.

14 **Q. What benefits will customers realize through the Company completing work in the**
15 **LVD Asset Relocations subprogram?**

16 A. This subprogram primarily functions to serve customer requests, whether they are internal
17 or external. However, every time old or obsolete equipment is replaced through this
18 subprogram, reliability improves because of the new equipment and the latest standards
19 implemented at the time. Relocations performed for HVD or substation work allow
20 maintenance work on the facilities before a failure causes an outage. Preparing the LVD
21 system for this work can save many customer-outage-minutes, as an outage would typically
22 de-energize more than one circuit on these systems, with an average of 1,000 customers
23 per circuit, for three hours or more. When LVD projects can support a planned load transfer

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1 for HVD and substation work, the Company can perform the work in a controlled
2 environment with little or no outage to customers. Additionally, as mentioned above, some
3 relocation requests provide clearance for large equipment like farm machinery and road
4 construction equipment. Without sufficient clearance, that machinery may contact the
5 LVD system, causing an outage, putting the operator or other members of the public in
6 danger, and causing thousands of dollars of damage. The LVD Lines Relocation
7 subprogram ensures that municipal requests are completed by the deadline.

8 **Q. How does the Company identify LVD Asset Relocations projects?**

9 A. The activity in this subprogram is entirely driven by requests from both external and
10 internal stakeholders. For all project requests, a party submits a request that includes
11 timelines for completion if applicable, the project purpose, contact information, and any
12 other pertinent information. For many municipal projects and large internal projects, the
13 Company holds site meetings to gather further information.

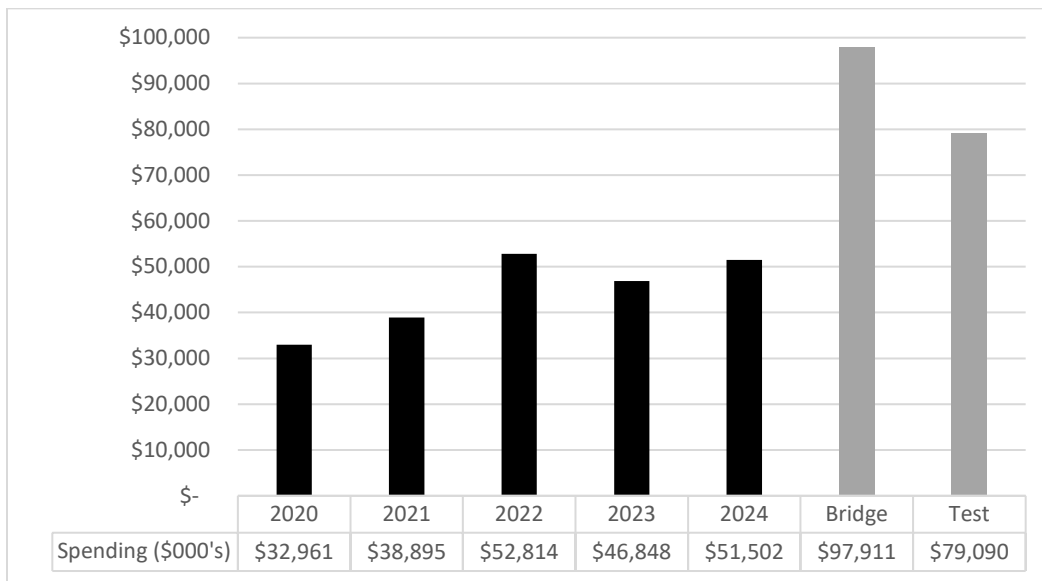
14 **Q. Please identify the projects that will be accomplished with the requested spending**
15 **level in the LVD Asset Relocations subprogram?**

16 A. The Company has identified known projects for the bridge period and test year, which are
17 listed in Exhibit A-166 (JMP-1), page 1, and Exhibit A-167 (JMP-2), page 1, respectively.
18 Due to the nature of the Asset Relocations program, only projects known in advance in the
19 LVD underbuild relocations investment category are listed. The Company developed the
20 projected costs of the projects in this exhibit considering estimated costs for materials and
21 labor and the Company's previous experience performing similar projects. These exhibits
22 also identify the location of the projects.

1 **Q. What are the Company’s projected bridge period and test year spending levels, for**
2 **which it is requesting cost recovery, in the LVD Asset Relocations subprogram?**

3 A. The Company is projecting LVD Asset Relocations capital expenditures of \$97,911,000 in
4 the bridge period, as shown in Exhibit A-113 (MPK-3), line 38, column (k), and
5 \$79,090,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 38, column (l).
6 The Company’s historical actual spending in the LVD Asset Relocations subprogram,
7 along with the bridge period and test year projections, are shown in Exhibit A-113
8 (MPK-3), line 38, and below in Figure 14.

FIGURE 14
LVD ASSET RELOCATIONS SUBPROGRAM EXPENDITURES



9 **Q. How did the Company develop its projected expenditures in this subprogram?**

10 A. The Company is projecting that make-ready work will increase in comparison to recent
11 history, especially as telecommunications companies request installation of new cellular
12 and broadband equipment on poles in part driven by federal grants. Increases in spending
13 from 2022 through the test year can be attributed to the government programs – Rural
14 Digital Opportunity Fund (“RDOF”) and the American Rescue Plan Act, which funded the

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Realizing Opportunity with Broadband Infrastructure Networks (“ROBIN”) grant – to install broadband to rural homes. In addition to those continuing programs, the application window for Broadband, Equity, Access and Deployment (“BEAD”) grant funding is early 2025, and scheduled to start construction in 2026. These programs are expected to influence the LVD Asset Relocations subprogram through 2028. The Company also anticipates continued LVD lines that need to be relocated, proportional to the Company’s work on the HVD system, to accommodate HVD projects, especially in the HVD Lines Reliability and HVD Lines Rehabilitation subprograms. In addition, the Company experienced a steady increase in expenditures from third-party and customer requests between 2020 and 2022. The Company anticipates a 1.6% expenditure increase in 2025 to relocate overhead and underground lines and services for the customer requested investment category, as shown in the equation below. These trends informed the Company’s projected needs for the bridge period and the test year.

$$Growth\ Rate = \left(\frac{Present}{Past} \right)^{\frac{1}{Years}} - 1 = \left(\frac{25,444,000}{23,527,000} \right)^{\frac{1}{5}} - 1 = 1.6\%$$

The bridge period spending amount for third-party and customer-requested relocations was determined based on recent trends in the number of relocation requests. Like LVD Lines New Business, relocation requests increased by 3.2% from 2020 to 2023. The LVD Underbuild investment category spend was determined based on the projects within the 2024 HVD projected expenditures. Company witness Megan L. Hayward discusses the HVD Lines Reliability projected expenditures.

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1 **Q. Can you provide further detail on how the broadband programs discussed above will**
2 **impact make-ready work?**

3 A. These programs are expected to significantly increase the number of make-ready work
4 orders that the Company will need to complete as part of this sub-program. This increase
5 is shown in Figure 15 below.

FIGURE 15
MAKE-READY FIELD COMPLETE WORK ORDERS BY YEAR

Year	Make-Ready Field Complete Orders
2019 actual	1,007
2020 actual	752
2021 actual	829
2022 actual	1,236
2023 actual	1,655
2024 actual	1,640
2025 Projected	5,547
2026 Projected	6,451
2027 Projected	6,816

6 **Q. Please explain how the capital expenditures projected for the bridge period and the**
7 **test year for this subprogram will be allocated across the four investment categories.**

8 A. The Company is projecting unit and capital expenditures in the bridge period and test year
9 for each investment category as identified in Figure 16 below.

FIGURE 16
LVD ASSET RELOCATIONS INVESTMENT CATEGORY EXPENDITURES

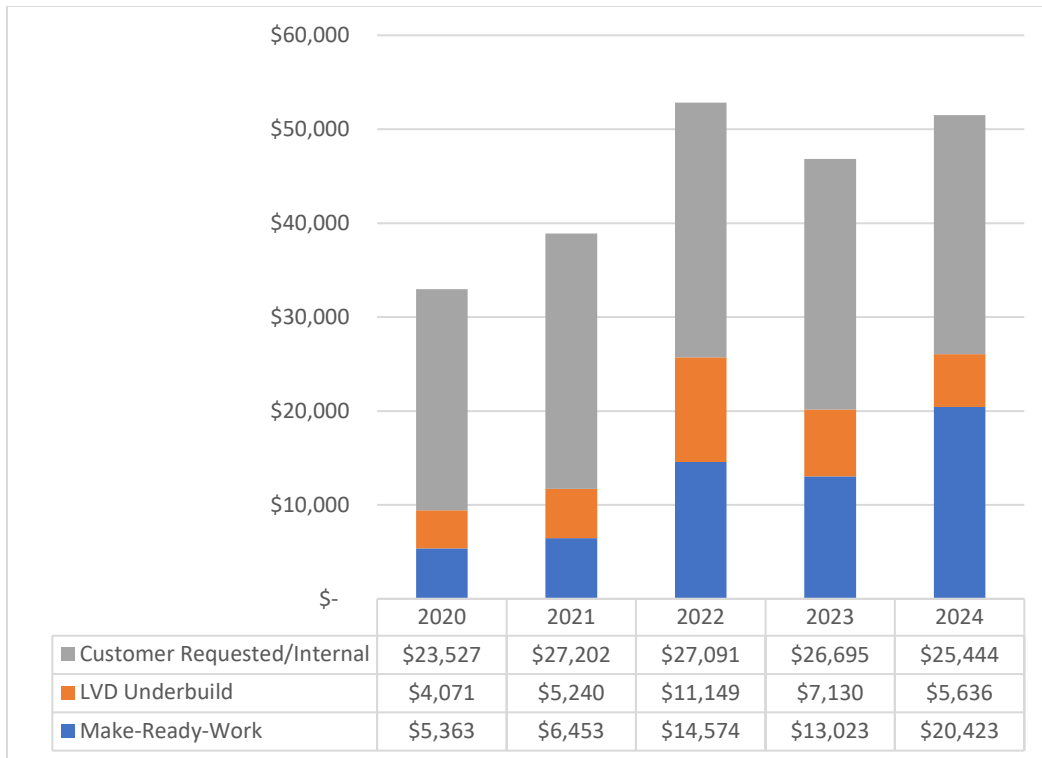
Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test year # of Units
Customer requested and other internal relocations	\$45,018,000	4,163	\$32,341,000	3,379
LVD underbuild relocations	\$7,056,000	N/A	\$7,484,000	N/A
Make-ready work	\$45,837,000	7,697	\$39,265,000	6,572
Total	\$97,911,000		\$79,090,000	

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Q. What has been the historical actual spending in the LVD Asset Relocations subprogram for the past five years?

A. The Company's historical actual spending in the LVD Asset Relocations subprogram for the past five years is shown in Figure 17 by investment category.

FIGURE 17
LVD ASSET RELOCATION 5-YEAR HISTORY



Q. Please explain the year-over-year variation in spending in this subprogram.

A. Because investment in this subprogram depends heavily on requests for relocation, the cost and amount of relocation projects can vary. In the years of 2020 and 2021, spending by the telecommunications companies was limited. Starting in 2022, telecommunication companies increased their spending as funds from the *American Rescue Plan Act* and the *Rural Digital Opportunity Fund* became available. Additionally, the Company needed to relocate an increasing number of LVD lines in 2019 and 2022 to accommodate HVD

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1 projects, particularly in locations where LVD lines were underbuilt on HVD structures.
2 The Company saw an increase in customer requested relocations in 2020 and 2021 due to
3 an increase in home remodeling work. The spending continued into 2022 and 2023 but
4 slowed as the interest rates rose at the end of the year.

5 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
6 **subprogram?**

7 A. No. Average unit cost is not a good measure of spend to predict the cost of an individual
8 project in this subprogram. There is a wide variance among work required as described in
9 the previous response.

10 **Reliability Program**

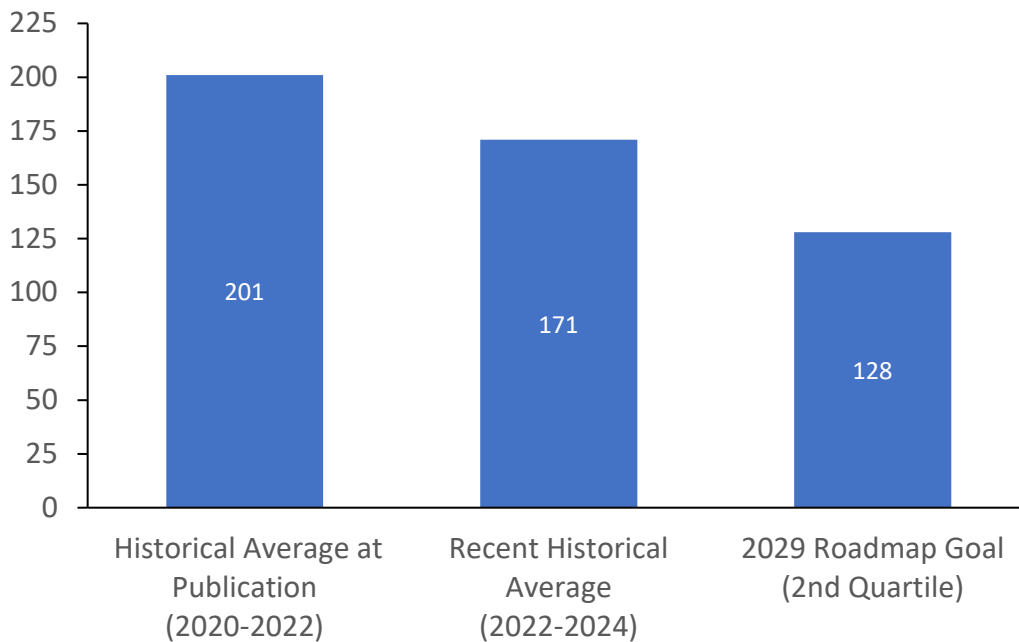
11 **Q. What is the purpose of the Reliability Program?**

12 A. The purpose of the Reliability Program is to ensure the long-term safe and reliable
13 operation of the electric distribution system, and to support the Company's SAIDI
14 glidepath, as introduced and discussed by Company witness Kelly. As Company witness
15 Kelly explains, the Company developed the Reliability Roadmap by modeling different
16 scenarios for increasingly severe weather and then defining a ramp-up in distribution
17 system investment to improve reliability in the face of that worsening weather. That plan
18 consists of four key categories of work: line clearing, hardening, inspections, and digital
19 automation. As I will discuss in this section of my testimony, the hardening work largely
20 takes place in the Reliability Program, particularly in the LVD Lines Reliability and
21 Resiliency subprograms. In these subprograms, the Company is increasing investment
22 relative to the historical levels that predated the Reliability Roadmap.

1 **Q. Why is the Company increasing Reliability investment compared to historical levels?**

2 A. As Company witness Kelly discusses in his testimony, the Company's scenario modeling
3 in the Reliability Roadmap indicated that climate change will result in more severe weather
4 and extreme heat, in turn creating increasing reliability and resiliency challenges for the
5 distribution system, with an increase in severe weather-related outages by the early 2030s,
6 compared to 2020 levels. Furthermore, Company witness Kelly explains that, absent the
7 investment levels identified in the Reliability Roadmap, the Company will not be able to
8 deliver the reliability that both the Commission and various stakeholders have indicated is
9 needed for customers. Specifically, the Company's investments will deliver second
10 quartile reliability performance by the end of the decade, as shown in Figure 18 below.

FIGURE 18
SAIDI EXCLUDING MEDS PROJECTIONS –RELIABILITY ROADMAP Goal



11 In each section of my testimony on the Reliability Program, I will explain how each
12 investment category is aligned with the investment plan laid out in the Reliability
13 Roadmap, leading to these SAIDI improvements.

1 **Q. The Reliability Roadmap identifies a reliable and resilient system as one of the**
2 **Company's distribution objectives. Is resiliency different from reliability?**

3 A. Yes, but resiliency and reliability are related. *Reliability* is defined as the ability of the
4 system to withstand normal variation and continue serving customers predictably. While
5 reliability investments focus on the typical days of the year, when conditions are normal,
6 resiliency investments are focused on storms and other extreme weather, which are only
7 projected to become more frequent, as described by Company witness Kelly. A resilient
8 electric system yields reliable customer service by withstanding these extreme storms.
9 While investments may initially target either reliability or resiliency, the outcome of the
10 investment will often improve both.

11 **Q. How do you define Resiliency?**

12 A. The Company defines resiliency as the ability of the system to withstand a major event –
13 particularly, a large and/or extreme storm – and the ability of the system to recover from a
14 major event where damage occurs, minimizing the needed restoration and repair time.

15 **Q. Are reliability and resiliency differentiated within the Reliability Program?**

16 A. Among LVD Reliability Program investments, most subprograms are primarily focused on
17 reliability improvements, targeted SAIDI reductions on blue-sky days. The Resiliency
18 subprogram is focused primarily on resiliency investments, which may not result in major
19 blue-sky SAIDI reductions, but are designed to harden the system and reduce the impact
20 of major weather events on customer outages.

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1 **Q. How does the Company measure the benefits of Reliability program investments?**

2 A. There are various means of measuring reliability benefits that will be discussed at various
3 points in my testimony, but one of the most important is the customer-outage-minute
4 benefit.

5 **Q. What is meant by a customer-outage-minute benefit?**

6 A. Customer-outage-minutes, sometimes shortened to customer-minutes, is a mathematical
7 product of the number of customers that experience an extended outage of electrical service
8 and the duration of outage measured in minutes. These numbers are gathered through the
9 Company's outage management systems for each outage. For example, a failure on the
10 LVD system that interrupts electrical service to 100 customers for 170 minutes would
11 accrue 17,000 customer-outage-minutes. A reliability project will reduce this number by
12 either reducing the probability of failure leading to an outage, the duration of the outage,
13 and/or the number of customers impacted by the failure and subsequent outage. The
14 planning engineer will determine the amount of savings based on both the historical outage
15 data of that part of the system and the expected effectiveness of the solution selected. For
16 example, if the historical average customer-outage-minutes of an LVD zone was
17 20,000 per year and the proposed project would reduce the probability of that outage by
18 70%, the customer-outage-minutes avoided by completing the work would be 14,000 (70%
19 of 20,000). In this way, the benefit of a distribution reliability project can be quantified.

20 **Q. What portion of the Reliability Program will your testimony discuss?**

21 A. My testimony will focus on the following LVD subprograms.

22 (i) LVD Lines Reliability;

23 (ii) LVD Repetitive Outages;

(iii) LVD Lines Rehabilitation; and

(iv) Resiliency.

Projected spending and benefits are explained in detail in the subprogram sections below.

LVD Lines Reliability

Q. What is the purpose of the LVD Lines Reliability subprogram?

A. The LVD Lines Reliability subprogram includes projects to ensure the long-term safe and reliable operation of the Company's LVD lines. The subprogram includes a diverse range of projects that are designed to address concerns on a given circuit or circuits.

Q. How does the Company identify LVD Lines Reliability projects?

A. The Company uses several critical inputs and analyses to aggregate multiple data sources to best target and prioritize reliability issues. The analyses used help identify specific areas to target investments based on probability of future issues and help prioritize projects that will deliver the greatest reliability improvements.

Q. What is the primary input in this process?

A. The primary input for deciding where to invest is data provided by the Reliability Analytics Engine ("RAE"). The RAE data is used to help the Company evaluate how to maximize the reliability benefit to customers through reduced outages.

Q. Please describe the RAE.

A. The RAE is a database used to analyze outage incident history and electric operations performance. The RAE arranges multiple data points in a manner that allows key reliability metrics (e.g., System Average Interruption Frequency Index ("SAIFI"), Customer Average Interruption Duration Index ("CAIDI"), and Customers Experiencing Multiple Interruptions ("CEMI")) to be calculated at varying levels of granularity. By combining

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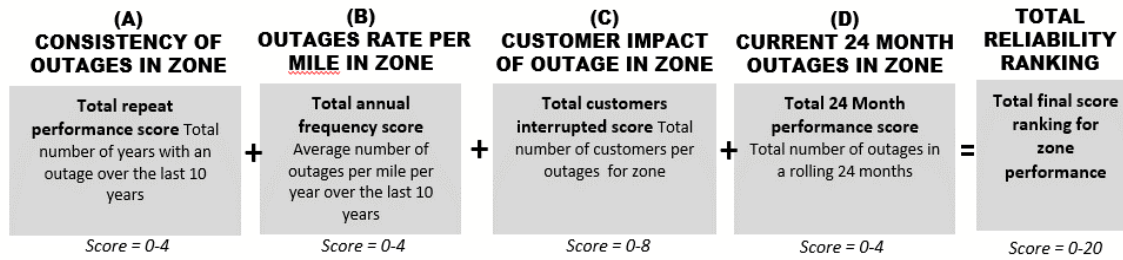
1 data from various sources, the RAE can also construct a complete timeline for all incidents
2 from initial outage to final restoration. This detailed timeline breaks down an outage into
3 analysis, dispatch, travel, and repair process steps, and calculates the time spent in each
4 step. The RAE also includes other sources such as line clearing data, callout success rates,
5 and historical project spending. These can be combined with other data to analyze
6 reliability. The RAE also produces monthly zonal analysis data that is reviewed by each
7 area's LVD circuit planner. This data is analyzed to determine zonal impact to LVD system
8 reliability.

9 **Q. What conclusions does the Company draw from this RAE analysis?**

10 A. By analyzing historical outage data across the LVD system, identifying trends, and
11 assessing zones with the greatest potential for reliability improvement, the RAE provides
12 a ranking of zones to target to maximize SAIDI reduction. Data is analyzed in four ways
13 —consistency of outages, outage rate, customer impact, and current year outages—to
14 determine the score for any given zone compared to all other zones on the LVD system
15 statewide.

16 The results of the analysis are totaled to determine the final score for any given
17 zone, as shown in Figure 19. Once reliability inputs are used to identify zones to target on
18 the LVD system, reliability projects are developed, evaluated, and prioritized to develop
19 an investment plan that maximizes the reliability benefit for customers.

FIGURE 19
ZONAL RANKING FORMULA



1 **Q. Does the Company consider anything besides RAE output when prioritizing projects?**

2 A. The RAE is but one tool – albeit a tool that pulls in many diverse types of data – that helps
3 create a zonal health score that then informs prioritization of projects. The zonal health
4 score considers important factors in prioritizing reliability projects, including consistency
5 of outages in the zone, outages rate per mile in the zone, customer impact of the outages in
6 the zone, and the current 24-month outages in the zone. Thus, the Company uses the zonal
7 health score to identify customers that are experiencing the poorest reliability and
8 prioritizes projects to improve reliability for those customers. The best use of Company
9 resources is for the Company to seek to address those areas that are experiencing the
10 poorest reliability. The Company typically does this on a “least-cost-best-fit” basis, which
11 is commonly recognized in the industry as an appropriate means for evaluating reliability
12 investments. Least-cost best-fit analyses consider the desired functionality or capability
13 on the distribution system, or the safety, reliability, or regulatory goals, along with the
14 lowest cost way to accomplish these goals.

15 **Q. Why does the Company utilize least-cost-best-fit analyses for this sub-program?**

16 A. The Company recognizes that interruptions to customers is a problem worth solving. Using
17 least-cost best-fit to select the method for addressing reliability concerns is preferable to
18 relying on cost-benefit ratios, which could result in concluding that a project that does not

1 pass a certain threshold is not worth completing, thus leaving the problem of those
2 customer interruptions unaddressed.

3 **Q. What other information does the Company consider when identifying potential LVD**
4 **Lines Reliability projects?**

5 A. The Company considers other circuit characteristics, such as car-pole accident history and
6 downed wires, to potentially add or reprioritize the list of projects. In addition, the
7 Company uses advanced metering infrastructure (“AMI”) data to identify voltage
8 deviations on the circuit, and to create projects to ensure service to customers is delivered
9 within the voltage range specified in Company tariffs.

10 **Q. What investment categories are included in the LVD Lines Reliability subprogram?**

11 A. The LVD Lines Reliability subprogram consists of five investment categories:

- 12 (i) targeted circuit improvements;
- 13 (ii) pole replacements;
- 14 (iii) ATR loops;
- 15 (iv) circuit exit enhancements; and
- 16 (v) ROW and easement acquisition.

17 **Targeted Circuit Improvements**

18 **Q. What does the Company include in targeted circuit investments?**

19 A. Targeted circuit improvements include several project types with customized solutions to
20 address specific reliability concerns. The Company employs four distinct strategies within
21 this investment category including:

- 22 (i) reducing the amount of non-standard voltage on the distribution system;
- 23 (ii) zonal health investments;

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- (iii) converting open-wire secondary to multiplex; and
- (iv) rejuvenating vintage underground cable.

The Company has been doing some amount of the kind of work contained in each strategy for many years, but only began calling out each strategy separately in Case No. U-21585, following the language used in the 2023 filing of the Reliability Roadmap. This allows the Company to provide more detail and transparency around the diverse types of work in the targeted circuit improvement investment category than was provided in earlier electric rate cases.

Reducing Non-Standard Voltage

Q. How does the Company reduce the amount of non-standard voltage?

A. Non-standard voltage conversion is discussed in the Reliability Roadmap. The Company converts distribution circuits and substations energized at non-standard voltages to one of the three standard voltages that Consumers Energy operates. The Company presently operates 13 general distribution voltage systems; the three standard operating voltages are 4.8/8.32 kV, 7.2/12.47 kV, and 14.4/24.9 kV grounded-wye. Systems dedicated to serving a single customer site are not within the scope of this category.

Q. Are there additional benefits of reducing the amount of non-standard voltage beyond improving reliability?

A. Yes. First and foremost, reducing the amount of non-standard voltage provides safety benefits, as described in the Reliability Roadmap and as discussed by Company witness Kelly. Also, in addition to improved reliability through customer-outage-minute savings, further benefits include:

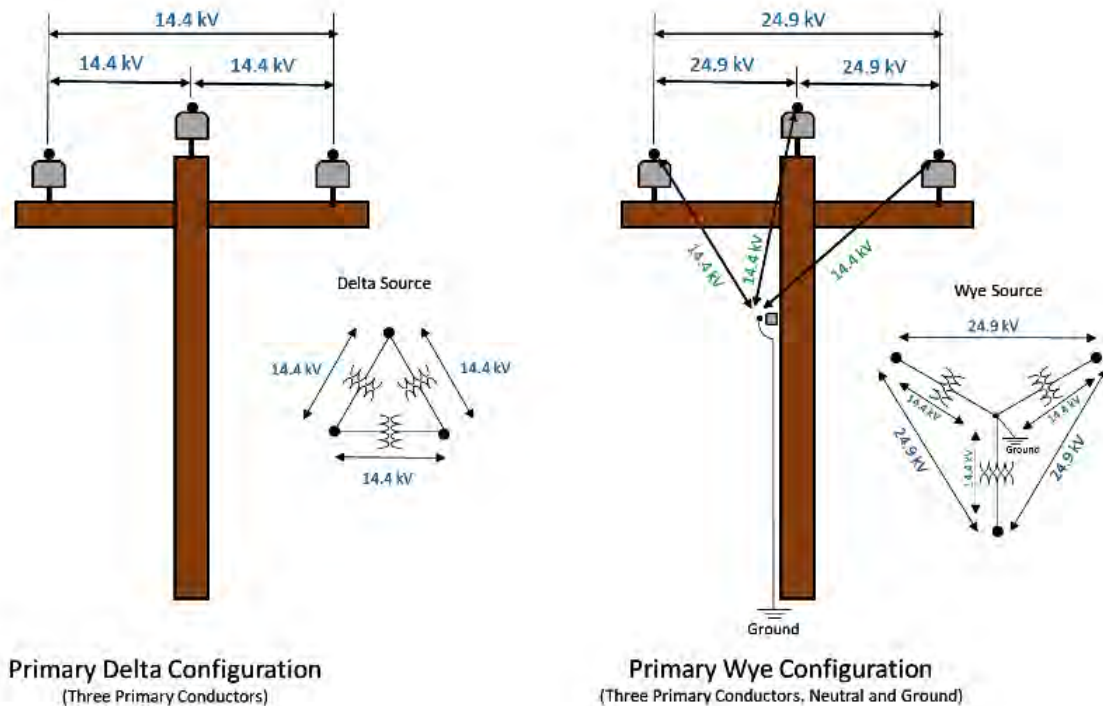
- Reduced system losses and increased system line capacity – Converting delta systems to grounded-wye reduces load current on primary lines, thereby

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1 increasing available line capacity. For the same electric load, the grounded-wye
2 system will carry 58% of the load current that the delta system carries (e.g., a
3 400 Amp rated conductor carrying 360 delta Amps (90% loaded) will carry 208
4 wye Amps (52% loaded) after the conversion). Since the amount of loss in an
5 electric system is proportionate to the square of the load current, reducing the
6 load current by voltage conversion lowers the electric loss associated with that
7 portion of the electric system. Further loss reduction is typically realized
8 through voltage conversion as older transformers and isolators are replaced as
9 part of the voltage conversion project.

- 10 • Reduced number of interrupted customers for single-phase faults – When a
11 single-phase fault occurs on the delta system, two primary phases are disrupted,
12 interrupting two-thirds of the customers; when a single-phase fault occurs on
13 the grounded-wye system, only one phase trips, interrupting one-third of the
14 customers.
- 15 • Increased system load transfer capability – Circuit conversions create the
16 opportunity to improve transfer capability between like systems and build a
17 platform for increased distribution automation and smart grid systems.
- 18 • Reduced equipment inventory – Eliminating the non-standard line transformer
19 inventory would reduce and eventually eliminate the need to maintain
20 non-standard line transformer inventory. Non-standard transformers are more
21 difficult to maintain in inventory in sufficient quantities, because suppliers
22 produce fewer of them. The Company experienced a shortage of transformers,
23 exacerbated by the need for non-standard voltages, in the past couple of years
24 leading to delays in connection of new customers.

FIGURE 20
ILLUSTRATION OF DELTA VS. WYE CONFIGURATIONS



Zonal Health Investments

Q. What are zonal health investments?

A. Zonal health investments are addressed in the section of the Reliability Roadmap on LVD circuit health. The Company's analysis has shown that 91% of customer interruptions happen on just 25% of line miles. Because of this, the Company focuses on or "targets" individual zones when assessing LVD asset health and mitigating the risk, instead of whole circuits. The Company assesses the health of each zone using the zonal health assessment rubric that is explained in the Reliability Roadmap and Figure 19 earlier in my direct testimony.

Q. When did the Company begin doing zonal health improvement work?

A. The Company began doing zonal health improvement work in 2013.

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1 **Q. Can you provide some illustrative examples of how zonal health investment projects**
2 **are selected?**

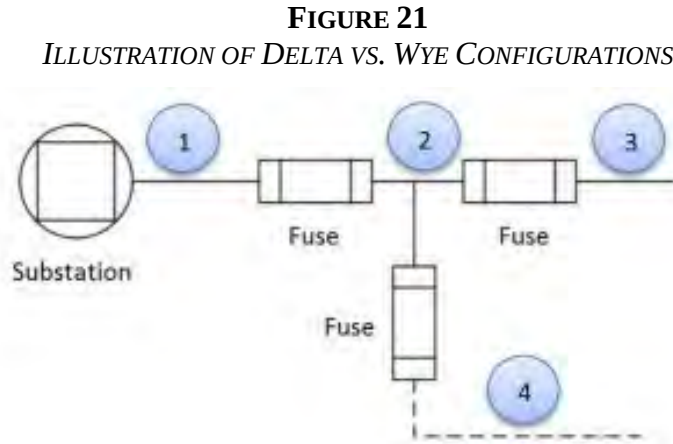
3 A. Test period examples include:

- 4 • Alger Substation, Skidway Circuit has a zone score of 18. The zone
5 experienced seven outages in 2024. The project will benefit 1,647 customers.
6 This project is to install 336 kcmil aluminum conductor steel reinforced
7 (“ACSR”) for one mile to split the load between the Skidway and Forest Lake
8 circuits both on Alger Substation. This will reduce customer counts on one
9 circuit, reduce exposure miles, and allow for future voltage conversion projects
10 for surrounding non-standard voltage substations. This project was selected
11 due to the high Zone Score, 2024 outage count, and the future benefits it can
12 provide to the surrounding substations.
- 13 • Camelot Lake Substation, Loomis Circuit, LCP 132 has a zone score of 17. The
14 zone has experienced seven outages in 2024, and one outage as of June 2025.
15 The project is to move 1 mile of line out of deep right of way (“ROW”) to the
16 roadside and install tree wire at the new location. The project will benefit 207
17 customers. The project was selected due to the high zone score, and high outage
18 count.
- 19 • Cowan Substation, Ramsdell Circuit has a zone score of 19. The zone
20 experienced two outages in 2024 and two outages as of January 2025. The
21 project is to replace the existing conductor with tree wire for 1.2 miles. The
22 project will benefit 1,386 customers. The project was selected for its high zone
23 score, and consistent outages..
- 24 • Frankfort Substation, Gateway Circuit, Zone 5554: This project will
25 reconductor approximately 1,300 feet of #8 copper conductor with #4 ACSR
26 and replace poles to current standards. #8 copper conductor is considered a
27 Hazard Conductor due to its fragility. It easily breaks, especially during storms,
28 and can be hard to splice if it continues to be brittle while crews are handling it.
29 While the zone score for this zone is only 6, the Company is selecting this
30 project due to concerns with the #8 copper conductor. This project will benefit
31 46 customers.
- 32 • The Gilson Substation Rock Lake Circuit Zone 801 project was selected as a
33 voltage conversion project. This zone has 6.8 miles of 11 kVA delta and this
34 project will convert 52 customers to 14.4/24.9 kVA wye. This will eliminate
35 6.8 miles of non-standard voltage.

1 **Q. Can you provide an illustration of how circuits are subdivided into zones?**

2 A. Yes. Please refer to Figure 21 below, which shows a circuit subdivided into four zones.

3 The Company has approximately 137,000 protective zones on its LVD system.



4 **Q. How do zonal health investments create benefits for customers?**

5 A. Zonal health investments improve the reliability of the Company's LVD system by
6 reducing the likelihood of an additional interruption over the next five years or more.

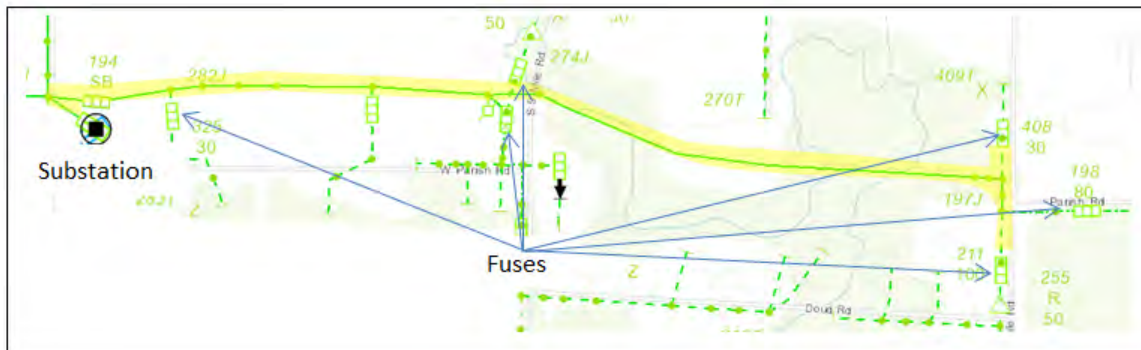
7 A zone targeted for improvement can include multiple protective device zones or a single
8 protective device zone. When the Company is aware that a circuit has deficiencies, based
9 on outage data, then the Company inspects the overhead lines on affected circuits to
10 identify appropriate solutions to improve reliability on those circuits. Solutions in zonal
11 health investments include, but are not limited to:

- 12 • Replacing equipment at the end of expected life, including poles, cross-arms,
13 switches, and conductor (overhead and underground);
- 14 • Installing new system protection devices, including fuses, switches, and
15 reclosers to reduce the size of the zone, and to reduce the number of customers
16 impacted by an interruption (see Figure 22 for an illustration of this work);
- 17 • Installing upgraded poles and composite cross arms to meet increased design
18 and construction standards;

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- Upgrading conductor at risk for contact with trees, typically in heavily wooded areas, to tree wire or aerial spacer cable to provide better tree protection. Both aerial spacer cable and tree wire are insulated wires that mitigate contact with trees and associated interruptions;
- Restoring underground cable that is no longer looped to re-establish redundancy;
- Improving system protection coordination and reach – following certain upgrades, protective devices may no longer coordinate (a systematic application of devices to ensure clearing of permanent faults) or reach (the zone or area of protection in which a fuse, recloser, or breaker will open within an acceptable timeframe);
- Improving the system's capability to isolate and transfer load for improved restoration time; and
- Improving voltage quality through equipment upgrades, reconductoring, circuit reconfiguration, and phase balancing.

FIGURE 22
ILLUSTRATION OF ZONE PROTECTION DEVICES



Q. Has the Company adjusted its LVD Lines Reliability approach?

A. Yes. As described earlier in the LVD Lines Demand Failures section, the Company took a new approach to LVD overhead line assessments in 2022, including completing the addition of high-value lateral fusing. This decreases SAIDI by isolating future faults to smaller sections of line, minimizing the number of customers affected per interruption, and minimizing the amount of time required for LVD line crews to patrol and identify the cause of the outage. EPRI validates this approach in their technical report, *Distribution Grid*

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*Resiliency: Prioritization of Options*⁵, Appendix D, page 13, noting that “[a]pplying sectionalizing devices can reduce sustained interruptions per mile by reducing the number of customers who are outaged by the initial event. Only those customers downstream of the protective device nearest the fault location are affected.” The Company plans to effectively complete this fusing effort in 2025.

Q. Can the Company demonstrate the benefits of zonal health investments?

A. Yes. The Company has measured the performance of circuit improvement projects by comparing the three years of outage history of the zone prior to investment to the outage history for the one to three years after investment. Zonal health improvement work has produced, on average, a 53% reduction in outages. Figure 23 illustrates zonal performance improvements following targeted circuit improvement projects in 2019 through 2023.

FIGURE 23

AGGREGATED IMPACT OF TARGETED CIRCUIT IMPROVEMENTS ON ZONAL PERFORMANCE

Project Year	Zonal Projects	Prior 3-Year Average Outages	Post 1-Year to 3-Year Average Outages	Percent Improvement
2019	151	280	94	66%
2020	146	206	59	71%
2021	249	347	132	62%
2022	1,394	199	119	40%
2023	2,884	274	195	28%
Weighted Average Improvement				53%

⁵ *Distribution Grid Resiliency: Prioritization of Options*, <https://www.epri.com/research/products/3002006668>

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1 **Q. Can you discuss the trend in percentage improvement following targeted**
2 **improvement projects?**

3 A. When interpreting Figure 23, it is important to note that the “zonal projects” column
4 includes fusing work in 2022 and 2023 in addition to more traditional zonal health
5 improvement work, which is why the number of projects increases by so much. Fusing
6 projects do not necessarily reduce the number of outages on a circuit, but they do reduce
7 the number of customers impacted by any particular outage. This impacts the before and
8 after outage numbers in the figure, and therefore the calculated percentage improvement.
9 It is important to note that traditional zonal health improvement work delivers substantial
10 outage reduction benefits, as shown in the data from 2021 and earlier.

11 **Q. Please provide some specific examples of recent zonal health improvement projects.**

12 A. Recent examples of these projects include:

- 13 • The overhead conductor on Cedar Springs Substation, Nelson Circuit,
14 Zone 150, was faulting two to three times per year between 2015 and 2021,
15 with four outages in 2020. A majority of the outages were caused by trees on
16 blue sky days and during storms. Each outage caused interruptions to
17 454 customers. In June 2022 the overhead conductor was replaced with tree
18 wire to prevent outages. This zone has not caused an outage since March 2022.
19 Between 2022 and 2025, this has saved approximately 177,000 customer-
20 outage-minutes annually.
- 21 • The overhead conductor on Foreman Substation, Cumberland Circuit Zone 646,
22 had two to five outages every year between 2015 and 2020, with another four
23 outages in 2022 averaging 62,500 customer-outage-minutes annually. The
24 causes were trees, inside and outside of ROW, and storms affecting
25 96 customers. In April 2023, the Company installed 0.8 miles of tree wire to
26 minimize the tree related outages. These customers have not experienced an
27 outage originating in this zone since the project’s completion.
- 28 • The underground cable on Calvin Substation, Rosemont Circuit, Zone 654, was
29 faulting once each year from 2015 through 2017, interrupting approximately
30 30 customers. This underground section was selected for underground
31 rejuvenation to inject the cable and replaced segments of cable in 2018 and
32 2019. Subsequently, those customers experienced no interruptions in 2018

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through 2023 due to this issue, saving approximately 43,000 annual customer-outage-minutes.

- Alamo Substation, Pine Grove Circuit, Zone 844, experienced three outages in 2021 and five outages in 2022, mainly due to tree issues, interrupting approximately 1,030 customers. In 2024, the Company upgraded a section of three-phase conductor to tree wire in an area that has lots of tree overhang. Shortly after this project was constructed, a large tree fell on the new tree wire. The tree wire held up the tree, subsequently saving approximately 227,300 customer-outage-minutes. The photo in Figure 24 below shows the tree being supported by the new tree-wire.

FIGURE 24

LVD TREE-WIRE CONSTRUCTION SUPPORTING A FALLEN TREE



Q. Are there specific benefits to projects that add lateral fuses?

A. Yes. The Company's analysis of lateral fuse additions completed in 2022 shows that these fuses prevented 43 circuit lockouts and avoided approximately 4.6 SAIDI minutes,

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1 excluding MEDs, in 2022. The lateral fuse additions completed have avoided
2 approximately 5.4 SAIDI minutes, excluding MEDs, in 2023 and 6.5 minutes in 2024.
3 Continued addition of lateral fuses in 2025 will further reduce SAIDI.

4 **Q. Does the Reliability Roadmap define a long-term workplan for zonal health**
5 **investments?**

6 A. Yes. In the Reliability Roadmap, the Company explains a plan to address all zones with a
7 zonal health score of 10 or greater, meaning each of these zones will need investment. The
8 2023 Reliability Roadmap provided a plan to do this work over a period of 20 years, with
9 a ramp-up in investment to addressing approximately 280 zones per year. However, as
10 Company witness Kelly explains in his direct testimony, the Company is adjusting this
11 plan to maintain the same SAIDI glidepath while accounting for increased line clearing
12 work, and the Company is now only ramping up to approximately 85 zones per year (this
13 increased line clearing work is tied, in part, to recommendations from Liberty Consulting
14 Group (“Liberty”) in their audit of the Company’s distribution system, filed in Case No.
15 U-21305 in September 2024). This change is reflected in the test year projections for zonal
16 health investments in the instant case. In every instance, the Company is planning projects
17 in zones that have been specifically identified as needing investment to deal with reliability
18 issues.

Converting Open-Wire Secondary to Multiplex

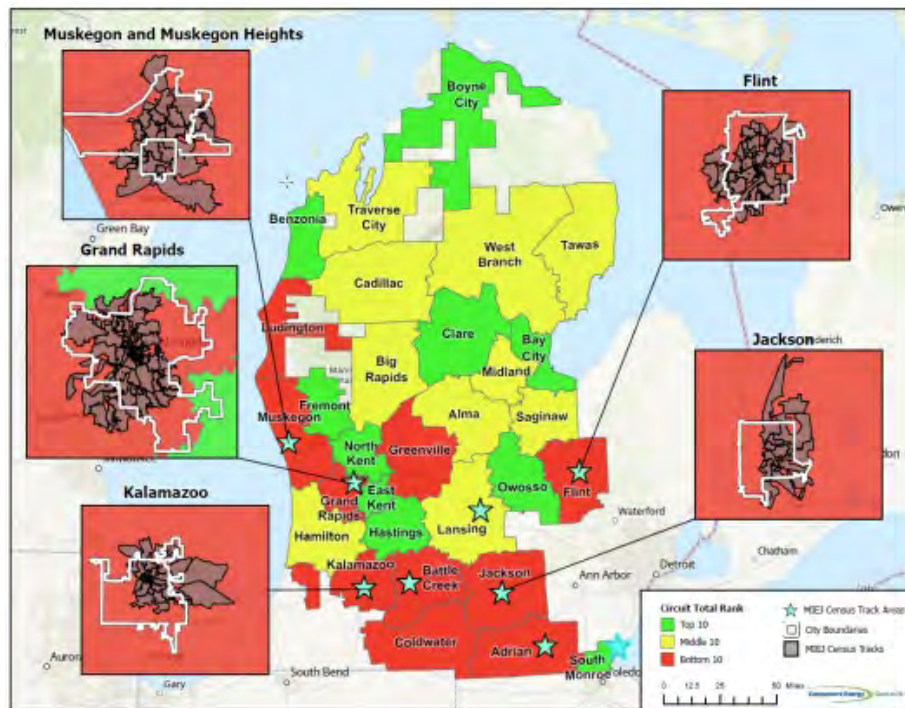
20 **Q. What are the issues facing secondary conductor on the Company’s distribution**
21 **system?**

22 A. As discussed in the Reliability Roadmap, secondary assets—located between the
23 distribution transformer and customer meter—are more challenging to repair than primary

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assets. This challenge is most prevalent on open-wire secondary, much of which is approaching the end of its life, and is brittle and not easily repaired, and thus is more vulnerable to tree damage. Individual outages on the secondary system may not affect large numbers of customers, but they are high-frequency and long in duration. As demonstrated in Figure 25 below, open-wire secondary has a disproportionately high impact on vulnerable communities.

FIGURE 25
SERVICE CENTER REGIONS WITH SECONDARY CIRCUIT PERFORMANCE



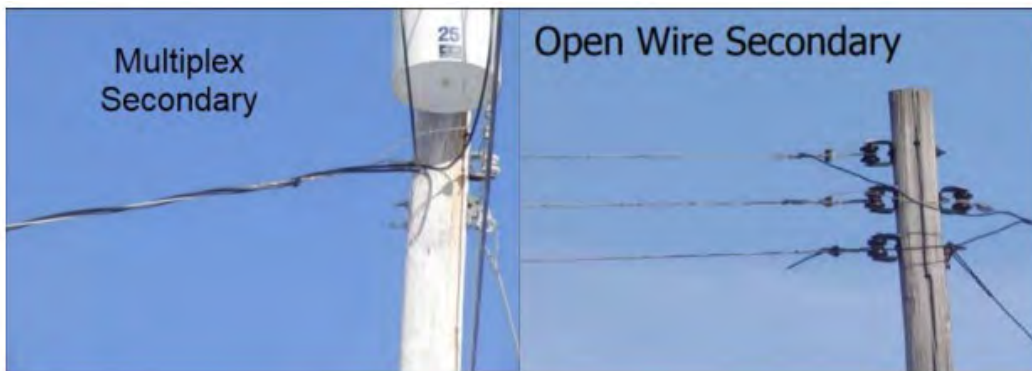
Q. How does the Company plan to address these concerns?

A. As explained in the Reliability Roadmap, the Company plans to programmatically convert its open-wire secondary to multiplex secondary, focusing on circuits with the highest risk scores, while ensuring equitable investments into vulnerable communities. The targeted secondary circuits in the instant case are included in the project list in Exhibit A-166 (JMP-1), page 12; and in Exhibit A-167 (JMP-2), page 6. In Case No. U-21585, the

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Commission approved one half of the Company's initially proposed investment in open wire secondary conversion, which equated to approximately \$14.4 million per year. The Company's proposed investments in the instant case are in line with this approved level. The Company's planned investments in the instant case focus heavily on vulnerable communities first; following the Commission's disallowances for these investments in Case No. U-21585, the Company is prioritizing using the remaining dollars to invest in those communities. The difference between open-wire secondary and multiplex secondary is shown in Figure 26 below.

FIGURE 26
MULTIPLEX VS. OPEN WIRE SECONDARY



Q. How does this conversion work benefit customers?

A. The most important benefit of doing this will be to improve safety by reducing the occurrence of difficult-to-repair wire downs, particularly in vulnerable communities.

The new multiplex secondary will also have more capacity, reducing the number of future upgrades that would be needed when customers adopt new technologies, such as heating electrification or electric vehicle (“EV”) charging, again helping customers in vulnerable communities to better access those opportunities. Typical open wire on the secondary system is able to carry between 95 Amps and 175 Amps, while multiplex is rated

1 for 195 Amps to 320 Amps. For homes with 200 Amp panels, open-wire secondary may
2 be approaching maximum capacity, which will not allow future growth for technologies
3 such as EVs, electrification, and distributed energy resources (“DERs”).

4 While the impact to systemwide SAIDI is modest, the outage duration benefits for
5 the impacted customers will be more substantial.

6 **Vintage Underground Cable Rejuvenation**

7 **Q. What are the issues facing vintage underground cable on the Company’s system?**

8 A. Vintage underground cable is discussed in the Reliability Roadmap. While underground
9 distribution provides many benefits, particularly for resiliency, the cable eventually begins
10 to degrade, which leads to a heightened risk of failure. This is a particular issue for 15 kV
11 vintage cable that dates to earlier than the 1980s, which makes up approximately
12 2,500 miles of the 9,500 miles of underground primary cable on the Company’s system.
13 This vintage cable is alsounjacketed, leaving the neutral conductors exposed to accelerated
14 deterioration from exposure to soil and moisture. Figure 27 below illustrates the locations
15 of this 15 kV vintage underground cable, along with locations of outages over the past three
16 years. Figure 28 illustrates the SAIDI contribution of the underground system, highlighting
17 that the most critical areas are in Grand Rapids, Flint, Traverse City, and Kalamazoo.

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FIGURE 27

UNDERGROUND CABLE: LOCATIONS OF 15 kV CABLE

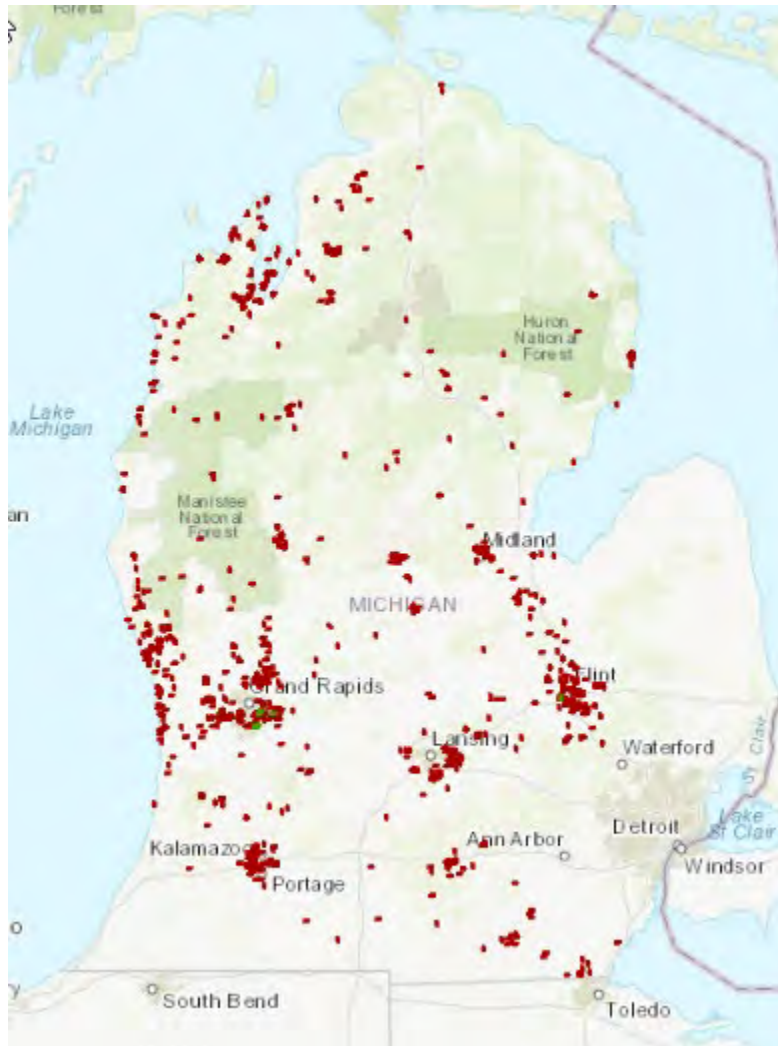
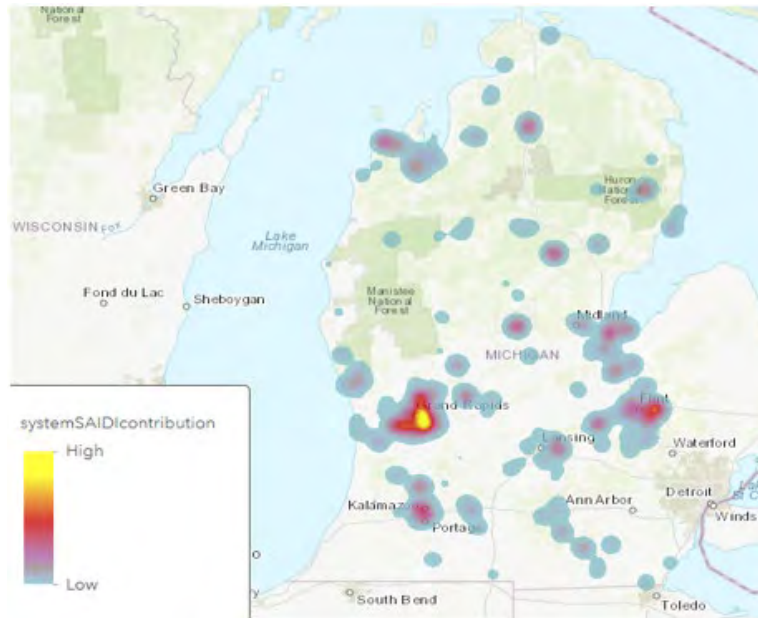


FIGURE 28
SAIDI CONTRIBUTION OF UNDERGROUND PRIMARY



Q. How does the Company plan to address these concerns?

A. To address these challenges and ensure that existing undergrounded lines continue providing resiliency for customers, the Company has begun using cable injection to rejuvenate the underground cable. This innovative process involves injecting a fluid insulation into the cable that then solidifies. This is less expensive than completely replacing the cable and is expected to extend cable life by a minimum of 25 additional years. Initially, the Company concentrated these investments in Grand Rapids and Flint because it has been most cost-effective for contractors to complete all work in one area before moving on to new locations. The Company will begin working in Traverse City as well in 2026. As explained in the Reliability Roadmap, the Company plans to rejuvenate all 15 kV cable installed between the 1960s and 1980s, over a period of nine years beginning in 2025, with a ramp-up to investing up to \$165 million each year.

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1 It is notable that Liberty’s distribution system audit highlighted the successes of vintage
2 underground cable rejuvenation. Specifically, they wrote, “Consumers has had success to
3 date in using rejuvenation, supported by long-term guarantees of effective operation by the
4 contractor who performs the work.” Liberty concluded that this work “reflects a sound
5 means for addressing vintage underground cable reliability problems.”⁶

Pole Replacements

7 **Q. What are the challenges currently facing LVD poles on the Company’s system?**

8 A. The Company’s LVD system includes over 1.5 million poles. Pole replacements in the
9 LVD Lines Reliability subprogram are completed based on two primary types of inputs.
10 First, poles are replaced in response to prior inspection results from previous years that
11 identified poles at risk of failure. The Company evaluates the results of those pole
12 inspections to determine if a simple pole replacement is required, and further evaluates
13 inspection results to determine if an entire pole line should be replaced or relocated to
14 improve reliability. The Company has had a backlog of poles identified in previous years’
15 inspections for some time, and has been working through this backlog through pole
16 replacement projects each year.

17 Second, following the development of the Reliability Roadmap the Company is
18 starting a program of groundline inspection of poles.

19 **Q. What is groundline inspection of poles?**

20 A. As specified in the Reliability Roadmap, the Company plans to replace all rejected poles
21 identified either through a groundline inspection on a 12-year cycle or through the regular
22 two-year visual inspection cycle of whole circuits. While these inspections are underway,

⁶ Liberty Final Report Part Two, pg. 69, September 23, 2024 in Case No. U-21305

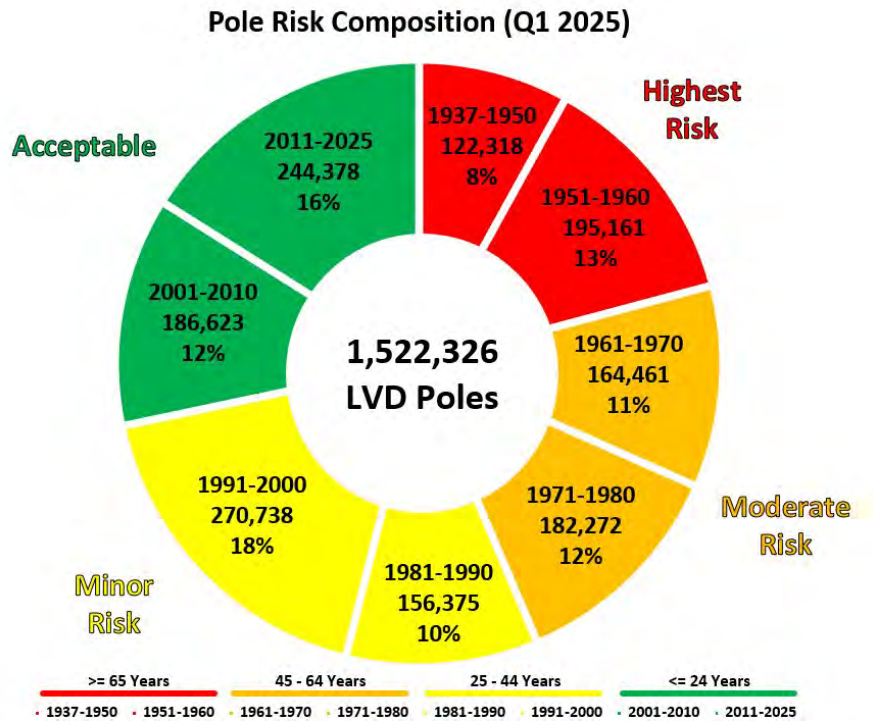
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the Company will continue to replace LVD poles identified in inspections that have not yet been completed, as described above. Based on system data, the Company estimates that approximately 10% of the poles on the LVD system will be classified as rejected based on these inspections, and the Company therefore projects that these inspections will identify 12,500 LVD poles per year for replacement. This anticipated rejection rate is based on known data about the vintage of poles on the Company's system, and the typical rejection rates of poles of a given vintage. A breakdown of the Company's pole vintage is shown in Figure 29 and a breakdown of LVD pole risk is shown in Figure 30. The highest risk poles carry a rejection rate of 15% or greater, and moderate risk poles carry a rejection rate of 10% to 15%.

FIGURE 29
LVD POLE VINTAGE BREAKDOWN

Vintage	Count	Percentage
2001-2025	431,001	28.31%
1981-2000	427,113	28.06%
1961-1980	346,733	22.78%
1960 and older	317,479	20.85%

FIGURE 30
LVD POLE RISK BREAKDOWN – Q1 2024



Regardless of how a pole was identified as being in need of replacement, the replacement of a pole prior to failure avoids the interruption of electrical service to customers and is considerably less expensive than replacing a pole after it has already failed.

In addition to reliability benefits, replacing poles prior to failure delivers significant benefits for public and employee safety. Falling poles can create a major public safety hazard, threatening both people and property. Furthermore, poles in poor asset health present major safety hazards for lineworkers who may need to climb the pole during restoration work, particularly if the pole gives way under the lineworker's weight.

Q. Are any pole replacements based on age alone?

A. No. This was contemplated in the 2023 version of the Reliability Roadmap, but Liberty's audit concluded that replacing all LVD poles greater than a certain age was not warranted. The Company concurs with this finding of the audit, and the Company has correspondingly

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1 reduced its projections of how many LVD poles will need to be replaced in future years
2 from what was shown in the 2023 Reliability Roadmap.

3 **Q. Is the Company taking any other actions to improve LVD poles?**

4 A. Yes. As discussed on page 70 of the Reliability Roadmap, over time the Company has
5 upgraded its minimum pole standards for the LVD primary system from Class 6 to Class 3.
6 As the Company replaces poles, it is installing poles that meet the new standard. These
7 larger Class 3 poles can endure wind gusts of up to 141 MPH without ice, or up to 71 MPH
8 when there is a half-inch of radial icing thickness. The Company no longer uses any
9 Class 5 or Class 6 poles in new construction or when replacing existing poles during storm
10 restoration. Furthermore, the Company began installing ductile iron poles as an alternative
11 to wood poles starting in 2024 for targeted locations. The ductile iron poles to be installed
12 are an equivalent to a Class 1 wood pole and will have a longer design life in comparison
13 to wood poles.

14 The difference in pole class capacities is shown in Figure 31 below. Improved pole
15 standards improve resiliency because poles are most challenged by external forces leading
16 to failure during severe weather rather than on blue-sky days.

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FIGURE 31
2023 NESC CODE⁷

No Significant Pole Deterioration as Noted in NESC Table 261-1			
NESC Grade C Construction - LVD - NESC 250C&D Load Factors			
Pole Size Minimum	No ICE, Max Wind Speed Prior to Failure (mph)	½ Inch Ice, Wind Speed Prior to Failure (mph)	1 Inch Ice, Wind Speed Prior to Failure (mph)
Class 6	109 mph	54 mph	39 mph
Class 5	116 mph	57 mph	43 mph
Class 4	129 mph	64 mph	49 mph
Class 3	141 mph	71 mph	54 mph
Class 2	157 mph	79 mph	60 mph
Class 1	170 mph	86 mph	67 mph

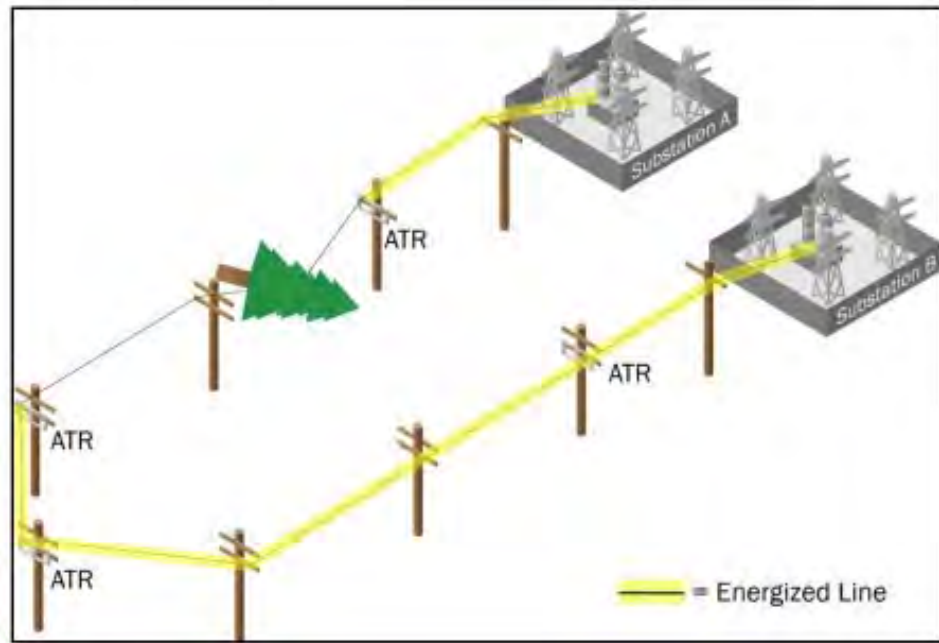
ATR Loops

Q. What are Automation Transfer Recloser (“ATR”) Loops?

A. As discussed, beginning on page 81 of the Reliability Roadmap, an ATR Loop is a set of reclosers installed between adjacent circuits that work simultaneously to automatically restore power to many impacted customers when power loss is detected. Figure 32 below shows how ATRs maintain power for a large part of the system following an incident that would have caused more interruptions to customers.

⁷ 2023 NESC, linear analysis, 1/0 ASCR 3 phase conductor with #4 ACSR Neutral, 350-foot spans, 45-foot pole lengths.

FIGURE 32
ILLUSTRATION OF ATR LOOP



1 Reclosers are single-phase or three-phase interrupting devices installed on electric
2 distribution lines for circuit sectionalizing. Reclosers typically have a predetermined
3 sequence of operation, tripping several times before locking out in the open position. An
4 ATR Loop recloser control includes additional programming beyond a standard recloser.
5 This programming automatically opens and closes the strategically placed reclosers to
6 enable impacted customers to be fed from the adjacent source within the loop. This
7 automated, fast response is the key factor driving customer reliability benefits.

8 ATR Loops have historically been installed as part of Grid Automation/
9 Modernization, but the Company has moved this work into the LVD Lines Reliability
10 subprogram because it is now a well-established practice, and is incorporated into the
11 Company's standard suite of reliability solutions. ATR Loops also provide a resiliency
12 benefit by allowing the system to better withstand major weather events, but since they

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also provide a benefit to blue-sky reliability, they are included in LVD Lines Reliability rather than in the Resiliency subprogram discussed later in my direct testimony.

Q. What historical benefits have ATR Loops provided customers?

A. The Company's first ATR Loop was installed in 2010 and, as of March 2023, there were 154 ATR Loops in service providing over 216,000 customers with a self-healing smart grid that prevents or minimizes the impacts of outages. Figure 33 shows the previous five years of tabulated actual benefits.

FIGURE 33
ATR LOOP HISTORICAL RELIABILITY BENEFITS

Year	Customer-Outages Prevented	Customer-Outage-Minutes Avoided
2019	34,333	10,334,000
2020	33,172	9,131,000
2021	36,098	23,375,000
2022	63,359	18,222,000
2023	69,339	18,059,000
Total	236,301	79,121,000

Circuit Exit Enhancements and ROW Projects

Q. What work does the Company include in circuit exit enhancements?

A. The Company installs circuit exit switches on each phase outside the substation fence, providing additional safety by creating an isolation point for line workers in case the substation (and substation equipment) becomes energized. If the substation becomes energized without having the circuit exit switches opened, the line workers could be at serious risk of contact with an energized line while working on that line.

Q. What work is included in ROW projects?

A. This investment category is used to procure necessary land or land rights for LVD projects, including both lines and substations. Acquiring the necessary land rights is essential to

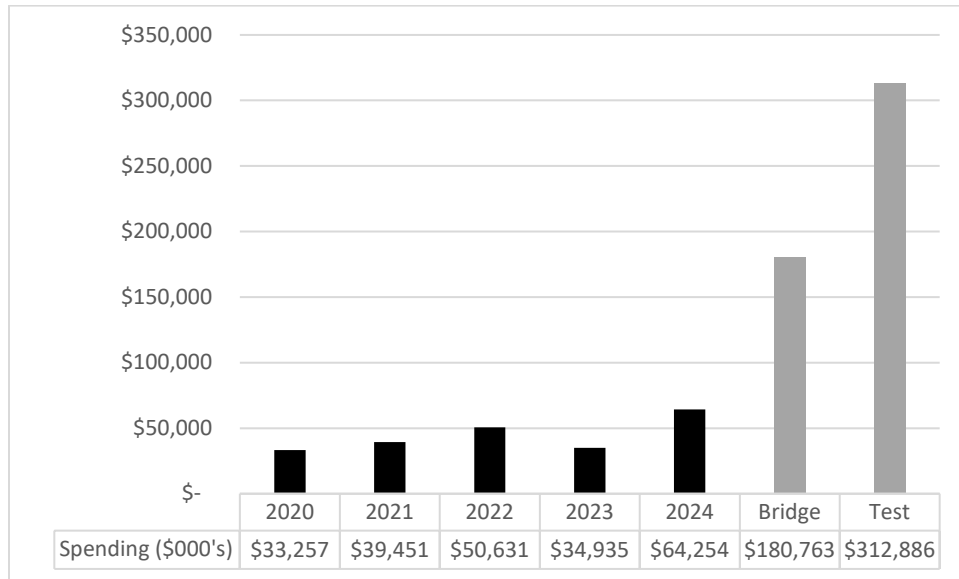
1 enabling LVD line projects across multiple capital subprograms. These projects are critical
2 to prepare for LVD construction and adequately support the project that is depending on
3 the new rights. New rights are required for new LVD line, LVD line relocation or rebuild
4 off-center, and improved easements where rights are determined to be inadequate. ROW
5 spending is generally correlated with overall levels of investment in other investment
6 categories in this sub-program, particularly with targeted circuit improvement categories.
7 The Company's projected increased investment in those other investment categories is
8 driving increased test year projections for ROW procurement in the instant case.

9 **LVD Lines Reliability: Overall Investment and Benefits**

10 **Q. What is the Company's projected bridge period and test year spending levels, for**
11 **which it is requesting cost recovery, in the LVD Lines Reliability subprogram?**

12 **A.** The Company is projecting LVD Lines Reliability capital expenditures of \$180,763,000 in
13 the bridge period, as shown in Exhibit A-113 (MPK-3), line 7, column (k), and
14 \$312,886,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 7, column (l). The
15 Company's historical actual spending in the LVD Lines Reliability subprogram, along with
16 the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 7,
17 and below in Figure 34.

FIGURE 34
LVD LINES RELIABILITY SUBPROGRAM EXPENDITURES



1 **Q. How will the projected LVD Lines Reliability expenditures support the Reliability**
2 **Roadmap?**

3 A. The increased LVD Lines Reliability expenditures outlined in this case are critical for the
4 Resilient Grid Plan that is defined in the Reliability Roadmap. The large increases in
5 investment in this subprogram are mostly driven by increased investments in zonal health
6 improvements and pole replacements. As the Reliability Roadmap makes clear, significant
7 investment is needed in improving LVD zonal health and replacing LVD poles to deliver
8 better reliability for customers, while managing the challenges of increasingly severe
9 weather. With projected benefits provided by investments in the Company's targeted zonal
10 improvements, which substantially reduce outages, and in ATR Loops, which can
11 completely mitigate customer outages, these investments are necessary to achieve the
12 Company's glidepath for reducing SAIDI.

13 Increased investment in this subprogram is also being driven by new investments
14 in voltage conversions and open-wire secondary conversions to multiplex which will

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deliver other non-reliability benefits to customers, particularly in vulnerable communities.

In the bridge period and test year, there are over 35 miles of open-wire secondary conversions and 20 miles of zonal health improvements identified on circuits serving vulnerable communities.

Q. Please explain how the capital expenditures projected for the bridge period and the test year for this subprogram will be allocated across the four investment categories.

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each investment category as identified in Figure 35 below.

FIGURE 35
LVD LINES RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Targeted Circuit Improvement <i>strategies</i> :				
• Zonal Health Improvements	\$61,320,000	497*	\$34,917,000	175*
• Secondary	\$19,680,000	66	\$14,670,000	49
• Voltage Conversions	\$8,427,000	44	\$33,115,000	283
• Underground Cable Rejuvenation	\$27,909,000	68	\$65,989,000	158
ATR Loops	\$17,539,000	39	\$22,299,000	40
Pole Replacements	\$29,711,000	3,076	\$127,500,000	12,500
Circuit Exit Projects	\$1,911,000	84	\$3,616,000	197
Right-of-way	\$6,188,000		\$17,667,000	
Total	\$180,763,000		\$312,886,000	

*Units for Zonal Health Improvements represent total number of projects; individual projects have varying types of units as shown in Exhibits A-166 (JMP-1) and A-167 (JMP-2).

Q. Please identify the projects that will be accomplished with the requested spending level in the LVD Lines Reliability subprogram.

A. The Company has identified projects for the bridge period, listed in Exhibit A-166 (JMP-1), pages 2 through 14, and for the test year, listed in Exhibit A-167 (JMP-2), pages 2

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1 through 10. The Company determined the projected costs of the projects in these exhibits
2 based on the specific work scope for each project and historical costs of materials and labor
3 from similar projects. These exhibits also identify the location and benefits of the projects.

4 **Q. Can you provide further explanation regarding the “units” columns in Figure 34**
5 **above for zonal health improvements?**

6 A. Zonal health improvements involve multiple types of projects, and it is difficult to
7 summarize them with a single kind of unit in this figure. Some zonal health improvement
8 projects involve addressing a certain number of line miles on a circuit, while others involve
9 installing a certain number of fuses, and for some the applicable unit is simply “1 project.”
10 These details are reflected in Exhibits A-166 (JMP-1) and A-167 (JMP-2). Figure 34
11 simply lists the total number of line items for zonal health improvements in those exhibits.

12 **Q. What are the different types of pole replacement projects listed in Exhibits A-166**
13 **(JMP-1) and A-167 (JMP-2)?**

14 A. As discussed above, the Company has two different types of pole replacement work:
15 projects to replace poles identified in prior years’ inspections, and projects to replace poles
16 identified during the Company’s new groundline inspection program. In Exhibit A-166
17 (JMP-1), page 2, the Company has listed a number of pole replacement projects of the first
18 type. Additionally, Exhibit A-166 (JMP-1), page 2, line 21, indicates that the Company
19 projects to replace 1,700 poles in response to groundline inspections during the bridge
20 period. Exhibit A-167 (JMP-2), page 6, line 24, indicates that the Company projects to
21 replace 12,750 poles in the test year in response to groundline inspections.

1 **Q. What benefits will customers realize through the Company completing work, at the**
2 **requested spending level, in the LVD Lines Reliability subprogram?**

3 A. LVD Lines Reliability projects form a critical part of the Company's glidepath for
4 improving SAIDI as part of the Resilient Grid Plan, as described in the Reliability
5 Roadmap, and by Company witness Kelly's testimony. In addition to driving system wide
6 SAIDI improvements, LVD Lines Reliability projects consistently provide immediate
7 benefits on the circuits or zones in which they are completed. The benefits for bridge
8 period and test year projects are identified in the Benefit Type and Benefit columns of
9 Exhibits A-166 (JMP-1), pages 2 through 14, and A-167 (JMP-2), pages 2 through 10.
10 Types of benefits identified on the exhibits, and summarized in Figure 36, include:

- 11 • Customer-outage-minutes avoided – as defined previously, this is the expected
12 reduction in the amount of outage time a group of customers would experience
13 once the project is complete;
- 14 • Customers impacted – defines the number of customers benefiting from a
15 project that improves voltage to ensure it remains within specifications for
16 normal conditions; and
- 17 • Increase Safety by Installing Isolation Point at Sub – these isolation points
18 installed just outside of the substation provide LVD line workers a visual open
19 that they can operate to safely work on the circuit.

FIGURE 36
LVD LINES RELIABILITY BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	382,538,000	36,180,590
Customers impacted	16,103	43,850
Increase Safety by Installing Isolation Point at Sub	84	197

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1 **Q. What are the historical unit costs for each of the LVD Lines Reliability investment**
2 **categories?**

3 A. Historical unit costs for three investment categories are provided in Figure 37. There are
4 no unit costs for the ROW investment category because units are not identified for this
5 work.

FIGURE 37
LVD LINES RELIABILITY INVESTMENT CATEGORY UNIT COSTS

Investment Categories	2020	2021	2022	2023	2024
Targeted circuit improvements	\$108,488 /project	\$112,093 /project	\$3,986 /project	\$3,498 /project	\$35,315 /project
Pole replacements	\$8,357 /pole	\$10,047 /pole	\$14,738 /pole	\$13,831 /pole	\$5,758 /project
Circuit exit enhancements	\$33,696 /project	\$43,658 /project	\$51,993 /project	\$46,842 /project	\$31,147 /project
ATR Loops	\$571,778 /loop	\$668,319 /loop	\$440,805 /loop	\$462,945 /loop	\$423,990 /loop

6 **Q. Please explain any variation in unit costs over time.**

7 A. Pole replacement unit costs increased in 2021 because Consumers Energy increased the
8 standard for pole class size for added reliability, added resiliency, and to align with industry
9 best practices. Increasing the Company's standard pole class size provides additional
10 strength to the system for projects taking place across the electric service territory. Pole
11 replacements take on average three to four hours to replace.

12 Replacement with increased sized poles, as part of upgrading to a higher pole class
13 as discussed above, helps prevent the pole from breaking during an event such as a tree
14 falling on the line. In the situation with a tree falling on a line, other weaker components
15 will fail such as crossarms, braces, etc. The repair time for pole top components such as
16 insulators and crossarms is substantially less than replacement of a pole that requires MISS
17 DIG notification and associated wait periods. The increase in pole class size impacts the

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cost of the pole ranging from \$50 to \$250 depending on class and height. Individual projects for targeted circuit improvements can vary widely in cost, based on specific project conditions and size of the projects, and as a result, the per-unit average cost can also vary. The lateral fuse addition projects completed in 2022 and 2023 each had a significantly lower cost than prior years' targeted circuit improvement projects. Accordingly, the unit cost for 2022 and 2023 for this investment category is less than prior years and less than in 2024. The unit cost for ATR Loops for 2022 and 2023 was lower than prior years because the Company completed some upgrades of existing loops, which have a lower cost, and focused its efforts on identifying lower cost loop projects. These lower cost loops avoided major LVD line upgrades for the new loops while maximizing benefit-cost ratios.

Q. Does an average unit cost accurately reflect the expected spending per project for this subprogram?

A. No. Average unit cost is not a good measure of spend to predict the cost of an individual project in this subprogram. There is a wide variance in work required ranging from \$2,000 to as high as \$3,000,000 or more per project. The Company builds a project plan for each year for this subprogram to achieve the reliability improvements needed for the LVD system and bases its investment levels on the cost of those projects.

LVD Repetitive Outages

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Repetitive Outages subprogram.

A. The LVD Repetitive Outages subprogram is similar to the LVD Lines Reliability subprogram in the types of work performed and in how projects are identified. However, the LVD Repetitive Outages subprogram is designed to specifically address areas of the

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1 distribution system that consistently experience recurring customer interruptions,
2 measured by the CEMI index, inclusive of MEDs. CEMI measures how many customers
3 have experienced more than a given number of interruptions in a particular year.
4 Investments in this program address issues of frequent interruptions primarily by targeting
5 specific zones for improvements.

6 The LVD Repetitive Outages subprogram is affected by the current version of the
7 Commission's Service Quality and Reliability Standards from Case No. U-20629 that went
8 into effect on April 10, 2023. Those standards specify that utility performance is
9 unacceptable if more than 6% of customers have four or more outages in a calendar year
10 (CEMI-4+), and they also establish new bill credit rules for customers with too-frequent
11 outages. In 2024, 10.9% of the Company's customers experienced four or more outages.
12 In its final Order in Case No. U-21585, the Commission noted that the Company's 2023
13 performance on CEMI-4+ was too high, which warranted the Company's planned
14 investment in this sub-program. When considering the 2024 CEMI-4+ results as well, it is
15 clear to the Company that it must dedicate more focus to this sub-program in order to bring
16 CEMI-4+ levels down to a more acceptable level. Additionally, the Commission has added
17 a CEMI metric to its new financial incentives and disincentives mechanism in Case No.
18 U-21400, providing further guidance that the Company must strive to address CEMI.

19 In order to meet the Commission's standards and expectations, increased
20 investment is needed for preventing repetitive outages.

21 **Q. How does the Company plan to address this concern?**

22 A. The Company plans to increase investment in the Repetitive Outages sub-program to
23 ensure it will achieve the Service Quality and Reliability Standard of 6% in the future. As

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described by Company witness Kelly, the Company is projecting a CEMI-4 of 8.2% in 2026 based upon the overall investment plan as approved by the Commission in Case No. U-21585. The Company needs to spend an additional \$33.2 million in 2026 and \$23.0 million in 2027 to achieve the standard beyond 2026, which is reflected in the Company's projected bridge period and test year investment levels in the instant case.

Q. How did the Company determine the needed scale of increased investment?

A. On average, it requires \$90,000 in investment to improve a zone that impacts 118 customers with repetitive outages. To mitigate repetitive outages for each 1% of customers for which CEMI performance is short of the Commission's standard, the Company will have to address 161 zones at the cost of \$14.45 million.

Q. What kinds of improvements are made for targeted zones in the Repetitive Outages sub-program?

A. Different solutions are considered depending on the specific conditions of the area being targeted. Depending on specific circuit conditions and attributes, typical investments include:

- System protection upgrades (e.g., fuses, switches, reclosers), using devices that maintain continuity of service by segmenting the electric distribution system into smaller sections, minimizing the number of customers affected by any individual outage;
- Replacing deteriorated or non-standard equipment such as poles, cross-arms, conductor, pins and insulators, lightning arrestors, non-standard equipment, and cutouts;
- Relocating portions of lines from dense tree or other poor access conditions for reduced tree interruptions and improved restoration time;
- Upgrading conductors that are at risk of contact with trees, typically in heavily wooded areas, to tree wire or aerial spacer cable to provide better tree protection, because both aerial spacer cable and tree wire are insulated wires that mitigate contact with trees and therefore associated interruptions; and

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- Relocating portions of overhead lines underground to reduce tree-related and severe weather interruptions.

Q. How does work in the LVD Repetitive Outages subprogram connect to the plans outlined in the Reliability Roadmap?

A. Work in the LVD Repetitive Outages subprogram is similar in nature to that in the LVD Lines Reliability subprogram, so the discussion is closely related to the Zonal Health Improvements component of the Reliability Roadmap. As established in the Reliability Roadmap, the Company is planning an increase in its LVD Zonal Health Investment Plan to make these circuit health improvements. While this increase primarily affects the LVD Lines Reliability subprogram, work in the LVD Repetitive Outages subprogram also supports the goal of addressing zones in poor health, in addition to its primary goal of addressing customers with high CEMI.

Q. Do the investments included in the repetitive outages subprogram also help support SAIFI improvements, as described in the Reliability Roadmap?

A. Yes. There is a correlation between SAIFI, including MEDs, and the MPSC's CEMI performance standard, which does include storms. Company witness Kelly, in the Historical System Performance section of his testimony, provides a forecast of SAIFI, including MEDs, and CEMI. To improve customer satisfaction, the Company continues to focus on sustained SAIFI performance to assist in meeting the Repetitive Outage performance standard. An improving SAIFI metric increases the probability that the CEMI-4+ metric will be met. By targeting investment to the worst performing areas of the distribution system, the Company expects to improve SAIDI, SAIFI, and CEMI. This reduces outage length and the frequency of outages experienced by customers.

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The proactive investments made to replace deteriorated assets and reduce customer exposure to outages improve employee and public safety. Furthermore, investments in the LVD Repetitive Outages subprogram reduce overall costs associated with emergent response for additional interruptions in the capital subprogram LVD Lines Demand Failures. The benefits for bridge period projects are identified in the Benefit Type and Benefit columns of Exhibit A-166 (JMP-1), pages 23 through 27 and Exhibit A-167 (JMP-2), pages 11 through 16 are consolidated into Figure 38 below. Types of benefits identified on the exhibit and shown below include customer-outage-minutes avoided. As defined previously, this is the expected reduction in the amount of outage time a group of customers would experience once the project is complete.

FIGURE 38
REPETITIVE OUTAGE BENEFITS SUMMARY

Benefit Categories	Bridge Period	Test Year
Customer-outage-minutes avoided	14,678,557	13,307,890

Q. How does the Company identify LVD Repetitive Outages projects?

A. RAE data, as discussed previously in the LVD Lines Reliability section of my direct testimony, is the primary input in deciding where to invest for repetitive outages. One RAE output is a monthly zonal analysis report, which is reviewed by each area's LVD circuit planner. The report is broken down to identify specific zones, showing the number of customers that experience repetitive outages in each zone of the circuit. By focusing on areas where customers are likely to experience four or more interruptions annually, the Company can develop projects that have the greatest reliability benefit for the highest number of customers first. To do this, the Company identifies zones with a high consistency ranking—a part of the zonal score illustrated in Figure 19—and a total

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1 reliability ranking below the threshold that would otherwise initiate a targeted circuit
2 improvement project in the LVD Lines Reliability subprogram. These zones are likely to
3 continue to experience interruptions, tend to have a smaller number of customers affected,
4 are typically farther away from the circuit source, and thus contribute significantly to
5 CEMI. Addressing these zones with Repetitive Outage projects may not produce the same
6 total customer minute savings as targeted circuit improvement projects but will
7 meaningfully improve CEMI.

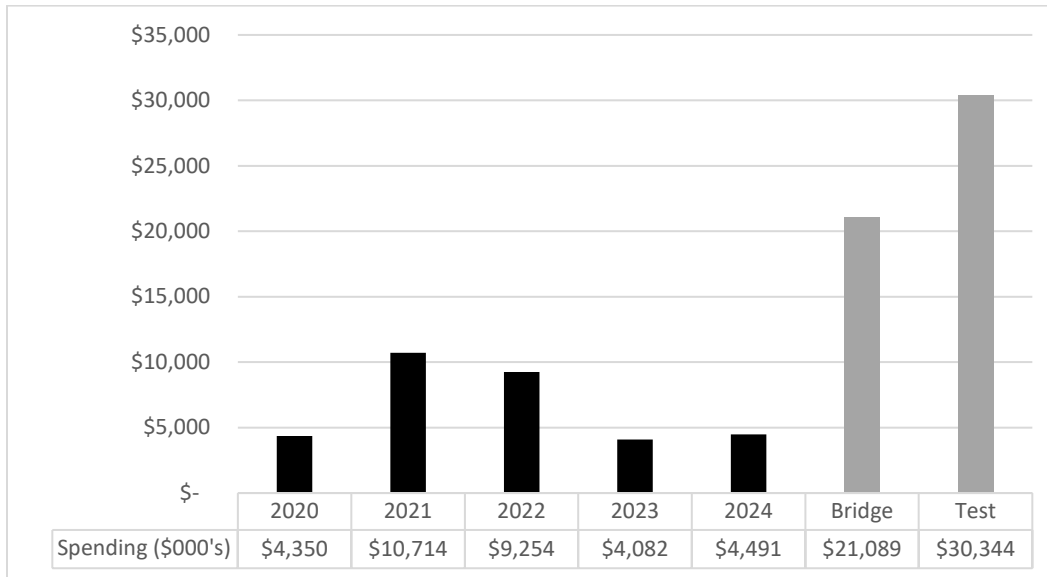
8 The Company also uses feedback from field operations to identify areas that may
9 also be creating outage concerns. This is then compared to the RAE and zonal report data
10 to pinpoint the causes as described previously.

11 In addition to using RAE data, the Company focuses on customers experiencing
12 CEMI-4+ and prioritizes them for projects in this subprogram, even if they might not have
13 otherwise been considered for investment prioritization in the LVD Lines Reliability
14 subprogram.

15 **Q. What are the Company's projected bridge period and test year spending levels, for**
16 **which it is requesting cost recovery, in the LVD Repetitive Outages subprogram?**

17 A. The Company is projecting LVD Repetitive Outages capital expenditures of \$21,089,000
18 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 12, column (k), and
19 \$30,344,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 12, column (l). The
20 Company is planning to complete 246 projects in the bridge period and 337 projects in the
21 test year. The Company's historical actual spending in the LVD Repetitive Outages
22 subprogram, along with the bridge period and test year projections, are shown in Exhibit
23 A-113 (MPK-3), line 12, and below in Figure 39.

FIGURE 39
LVD REPETITIVE OUTAGES SUBPROGRAM EXPENDITURES



1 **Q. Please identify the projects that will be accomplished with the requested spending**
2 **level in the LVD Repetitive Outages subprogram.**

3 A. The Company has identified projects for the bridge period, listed in Exhibit A-166 (JMP-1),
4 pages 23 through 27 and Exhibit A-167 (JMP-2), pages 11 through 16. The Company
5 developed the projected costs of the projects in the exhibit considering typical costs for
6 materials and labor, and the Company's previous experience performing similar projects.
7 This exhibit also identifies the location and benefits of the projects. While projects for the
8 bridge period have been identified and listed for this subprogram, the Company will
9 continue to evaluate areas on the system, developing solutions for those areas following
10 the process described below, and potentially reprioritizing work based on these evaluations.

11 Unit costs are higher in the bridge period and test year in this case than historical
12 averages. The Company recognizes that CEMI performance is not improving significantly,
13 even as it addresses anomalies identified in inspections and completes lateral fusing within
14 other subprograms. Therefore, the Company is shifting investments within this subprogram

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1 to focus on more robust, and more expensive, hardening projects such as line relocation,
2 undergrounding, and replacing bare wire with tree resistant wire.

3 **Q. Please explain the year-over-year variation in spending in this subprogram.**

4 A. Overall investment in this subprogram was lower in 2023 than in earlier years as the
5 Company focused on addressing anomalies identified during inspections, targeted zone
6 projects, and overhead to underground relocation projects. Shifting investment from
7 Repetitive Outages to LVD Lines Reliability and LVD Resiliency accomplishes the same
8 goal of reducing SAIDI and CEMI. Investment levels increased modestly from 2023 to
9 2024. The purpose of increasing investment in this case from 2024 levels is to reduce the
10 number of repeat outages a customer experiences once poor performance is identified, even
11 if the SAIDI benefit would not prioritize the project in LVD Lines Reliability.

12 **Q. In its final Order in Case No. U-21585, the Commission directed the Company to show**
13 **that these dollars were spent on addressing reliability in LVD repetitive outages in**
14 **this sub-program. What are you presenting in response to this direction?**

15 A. Please refer to Exhibit A-169 (JMP-4). This exhibit identifies all of the projects in the
16 LVD Repetitive Outages sub-program that had substantive investment in 2023 and/or
17 2024, and shows how many outages occurred both before and after work was completed.
18 In reviewing this exhibit, it is important to note that the total dollars for each year does not
19 exactly match the historical investment levels shown in Exhibit A-113 (MPK-3). In a given
20 year, all sub-programs include some costs and some accounting credits related to closing
21 out prior year projects. As noted above, the purpose of Exhibit A-169 (JMP-4) is to show
22 projects that had substantive investment in the years in question.

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As has already been stated, the Company did invest less in LVD Repetitive Outages in 2023 and 2024 than in some other recent years, for reasons already discussed. However, the money that was invested in LVD Repetitive Outages in those years did go toward repetitive outage projects.

Q. What benefits will customers see from continued investment in the LVD Repetitive Outages subprogram?

A. Continued investment in the LVD Repetitive Outage subprogram, at the projected levels, is necessary for the Company to address customers with high CEMI and for the Company to meet the Commission's CEMI-4+ standard.

LVD Lines Rehabilitation

Q. Please explain what projects, activities, and other types of work will be enabled by expenditures in the LVD Lines Rehabilitation subprogram.

A. The LVD Lines Rehabilitation subprogram includes capital repair or replacement of LVD lines equipment that has not actually failed but has been assessed to be at risk of failure in the near term. This subprogram consists of four investment categories:

- (i) imminent rehabilitation;
- (ii) meter voltage anomalies;
- (iii) subsurface transformer replacements; and
- (iv) modem replacement program.

Q. Are any of these investment categories new in recent years?

A. Yes. Subsurface transformer replacements was a new investment category in Case No. U-21585. It represents work that was newly prioritized during the asset health analysis that informed the 2023 Reliability Roadmap. Additionally, the meter voltage anomalies

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investment category is being newly defined in the instant case, based on voltage anomalies that the Company has recently begun to identify using its AMI. This effort was driven in part from the Commission's final Order in Case No. U-21389, directing the Company to continue identifying use cases for value-focused AMI metrics.

Q. Has this subprogram historically included any other investment categories?

A. Yes. Prior to 2024, this subprogram included an investment category called Security Assessment Repairs. As the Company initially explained in Case No. U-21389, that work will now be completed within the LVD Lines Demand Failures subprogram based on just P1 and P2 anomalies that are identified in inspections. If Priority 3 ("P3") or Priority 4 ("P4") anomalies are identified, they may be prioritized for action in the imminent rehabilitation investment category in this subprogram. Figure 40 presents the types of hazards classified as P3 and P4. The hazards are listed by the priority code for the anomaly.

FIGURE 40
LVD SECURITY ASSESSMENT HAZARD CODES

Code	Description
P3 - Failure Expected Before Next Inspection	
P3A	Broken Guy - Leaning Pole
P3B	Pole: Damaged
P4 - Heightened Risk of Failure	
P4A	Broken/Missing Cross-arm Braces
P4B	Broken Guy - Non-Leaning Pole
P4C	Damaged Equipment (Transformers, Reclosers, Etc.)
P4D	Lightning/Flashover Burn Marks
P4E	Poorly Sagged Line

Q. Please explain the imminent rehabilitation investment category.

A. The imminent rehabilitation category addresses issues that arise in which an actual failure has not occurred, but repair or replacement is required to prevent outages and the additional expenses associated with fixing following failure as opposed to doing planned, straight-time work with lower unit costs and higher efficiency. Imminent rehabilitation

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1 projects deal with conditions identified outside the Company's inspection cycles and
2 normal planning work, but there is no immediate need for repair as there would be with
3 LVD Lines Demand Failures projects. Imminent rehabilitation projects include:

- 4 • P3 and P4 conditions, as identified in Figure 40, may be addressed in this
5 investment category, such as replacing poles with visible damage or
6 deterioration identified outside of the inspection cycle by line crews or
7 customers.
- 8 • Underground cable repair after a fault is isolated and customers are restored
9 under service restoration activities. If this is the first time the section of line
10 has faulted, the Company typically will expose the fault and splice it. If this
11 section or area has experienced multiple faults or the vintage of the cable
12 warrants replacement, the Company will develop a project to replace the faulted
13 section of cable and, in some cases, adjacent sections of cable as well.
- 14 • Underground padmount equipment may require relocation or replacement due
15 to ground shifting that causes leaning or sinking.
- 16 • Underground padmount equipment inspection replacement. Each year
17 padmounted equipment is visually inspected around the exterior for any signs
18 of oil leaking or holes that expose electrical components. When found, the
19 equipment is replaced.
- 20 • Primary or secondary voltage improvements identified through customer
21 complaints, power flow analyses, or line crew reports and include projects such
22 as transformer replacement, conductor upgrades, load balancing, or voltage
23 conditioning device installation such as capacitor banks or voltage regulators.
- 24 • Deteriorated conductor or equipment replacement, including replacement of
25 secondary conductors that are losing the protective coating, severely rusting
26 equipment, or any wear and tear on the conductor that requires replacement.
- 27 • Radio frequency interference projects requiring pole top component or other
28 equipment replacements to resolve interference to communications, radios, and
29 other devices as required by Federal Communications Commission rules.
- 30 • Clearance violations of conductor or equipment with respect to structures or the
31 ground that are not an immediate risk requiring relocation, pole upgrades, or
32 new pole installations.

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1 **Q. Please describe the general inputs that the Company uses to identify issues that must**
2 **be addressed by the imminent rehabilitation investment category.**

3 A. The Company collects data through its electric operations organization. For example, there
4 may be locations that electric operations employees have frequently visited to restore
5 service for a failed underground cable in the same subdivision. This team conveys this
6 information to LVD circuit planners so they can investigate and create a project for a full
7 replacement of the underground cable, and possibly live-front transformers or padmounted
8 switching equipment in that subdivision, if necessary.

9 **Q. Please explain the meter voltage anomalies investment category.**

10 A. Rule 702 of the Commission's Standards of Quality of Services requires that the Company
11 provide customers with voltage that is $\pm 5\%$ of nominal voltage. The Company is able to
12 use its AMI for continuous monitoring of voltage at the service delivery point to customers,
13 and from this the Company knows that over 99% of customers receive voltage at compliant
14 levels. However, voltage anomalies do occur. When voltage is unacceptably low, this is
15 typically due to heavily loaded secondary and line transformers. When voltage is
16 moderately high (between 5% and 10% greater than nominal), this is typically due to
17 voltage regulation device issues. When voltage is greater than 10% above nominal, this is
18 typically due to internally-faulted line transformers that are still energized. The large
19 majority of voltage anomalies fall in the second of these categories. Historically, the
20 Company has fixed voltage anomalies as they are reported by customers on a reactive basis,
21 although in some cases a customer may not be aware if their voltage is too high or too low.
22 Going forward, though, the Company plans to use its AMI data to proactively address
23 voltage compliance concerns, and is therefore proposing to invest in correcting all three

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1 voltage anomaly causes, and will replace line transformers, mitigate regulator issues, and
2 mitigate low voltage secondary issues. This is also discussed in the Reliability Roadmap.

3 **Q. Please explain the modem replacement program investment category.**

4 A. The Company has begun a project to replace cellular modems that are installed inside
5 control devices (e.g., Capacitors and Line Voltage Regulators) throughout the LVD grid.
6 The present vendor of the Company's cellular modems announced a cessation of
7 manufacturing in 2020 and informed the Company that it will end support in 2029. An end
8 of support announcement means that security patches, firmware updates, and hardware
9 support/repair will no longer be available, which negatively impacts equipment reliability
10 and security. The security patches protect the Company from external parties accessing
11 the data and other cyber threats. Also, the equipment hardware will no longer be available,
12 reducing or eliminating the capabilities enabled by automation and conservation voltage
13 reduction ("CVR"). Due to the large quantity, geographic locations, and physical effort
14 needed to replace each modem, it is imperative to begin replacement efforts prior to the
15 end of support date. Over the course of the following years, the Company will replace the
16 total population of 5,000 cellular modems, completing approximately 800 replacements
17 per year.

18 **Q. Please explain the subsurface transformer replacement investment category.**

19 A. As discussed, starting on page 60 of the Reliability Roadmap, the Company's underground
20 system has 159 of its original subsurface transformers still installed. These transformers
21 do not have a major impact on reliability but do pose a safety risk for Company employees
22 and the public. Since they are underground, employees have difficulty accessing and
23 repairing them when they fail, and their location makes it difficult for members of the

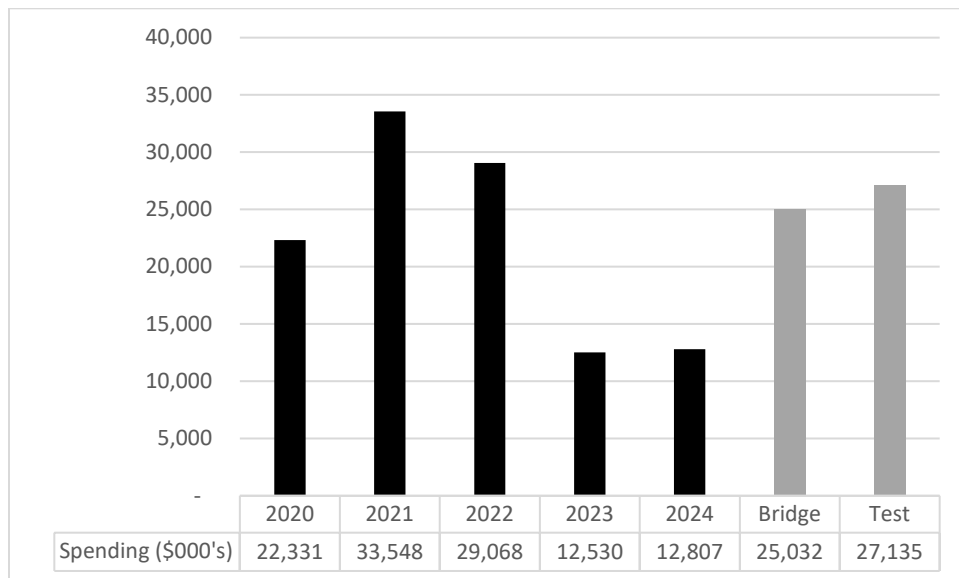
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public to recognize them and take care to avoid them. When subsurface transformers do fail, outages last approximately four times as long as during padmount transformer failures, given the difficulty of repair, and subsurface transformers are also prone to leaking subterranean oil. To address these risks, the Company plans to replace all subsurface transformers with padmount transformers by the end of 2027.

Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Lines Rehabilitation subprogram?

A. The Company is projecting LVD Lines Rehabilitation capital expenditures of \$25,032,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 17, column (k), and \$27,135,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 17, column (l). The Company's historical actual spending in the LVD Lines Rehabilitation subprogram, along with the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 17, and below in Figure 41.

FIGURE 41
LVD LINES REHABILITATION SUBPROGRAM EXPENDITURES



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1 **Q. How did the Company develop its projected expenditures in this subprogram?**

2 A. While the Company now addresses security assessments in the LVD Lines Demand
3 Failures sub-program (which led to lower investment levels in this sub-program in 2023
4 and 2024), the levels of investment for the bridge period and test year will continue to
5 address system deterioration and the resulting anomalies identified on the system. The
6 bridge period and test year also include the newer investment categories for modem
7 replacements and subsurface transformer replacements as discussed, and the new
8 investment category for meter voltage anomalies. The bridge period and test year spending
9 amounts will enable the investment needed to complete the projects identified.

10 **Q. Please explain how the capital expenditures projected for the bridge period and the**
11 **test year for this subprogram will be allocated across the three investment categories.**

12 A. The Company is projecting unit and capital expenditures in the bridge period and the test
13 year for each investment category as identified in Figure 42.

FIGURE 42
LVD LINES REHABILITATION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Imminent rehabilitation	\$15,120,000	442	\$9,413,000	165
Subsurface transformers	\$528,000	15	\$3,181,000	54
Modem Replacement Program	\$2,998,000	800	\$2,988,000	800
Meter Voltage Anomalies	\$6,386,000	N/A	\$11,553,000	N/A
Total	\$25,032,000		\$27,135,000	

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1 **Q. Please identify the projects that will be accomplished with the requested spending**
2 **level in the LVD Lines Rehabilitation subprogram.**

3 A. The Company has identified projects for the bridge period, listed in Exhibit A-166 (JMP-1),
4 pages 15 through 22, and for the test year, listed in Exhibit A-167 (JMP-2), pages 17
5 through 20. The Company developed the projected costs of the projects in these exhibits
6 considering estimated costs for materials and labor and the Company's previous experience
7 performing similar projects. These exhibits also identify the location and benefits of the
8 projects. Note that the Company only creates orders for specific modems close to the time
9 that they are replaced, so there are no specific projects listed for this investment category.
10 Spending amounts are based on a continuation of the same volume of work going forward.
11 Additionally, the Company does not have specific projects identified for meter voltage
12 anomalies. The Company will identify specific proactive projects for this investment
13 category closer to the time of project execution based on up-to-date AMI data; the projected
14 work volume for meter voltage anomalies is based on the historical levels of anomalies
15 visible in the AMI data. Finally, it is important to note that the Company only has five
16 total subsurface transformer projects in the test year, but this is due to one large project
17 replacing many subsurface transformers in a subdivision.

18 **Q. Please explain the year-over-year variation in spending in this subprogram.**

19 A. In 2021, the Company addressed P3 and P4 deteriorated system assets identified in security
20 assessments and imminent rehabilitation. That increase over 2020 enabled the completion
21 of the circuits with previously completed security assessments. Material delivery
22 challenges in 2022 inhibited work in other subprograms resulting in crews completing
23 more imminent rehabilitation work which used materials that were more available.

1 **Q. What benefits will customers realize through the Company completing work in the**
2 **LVD Lines Rehabilitation subprogram?**

3 A. The LVD Lines Rehabilitation subprogram addresses conditions that could result in
4 interruptions to customers or present unacceptable system operating conditions and,
5 therefore, provides a benefit to customers by reducing the likelihood of future actual
6 failures. By replacing or rehabilitating equipment before it fails, work can be completed
7 in a more economical manner by having the correct materials and resources in place before
8 work begins. The approximate number of customers benefitting from known bridge period
9 and test year projects are identified in the Benefit Type and Benefit columns of Exhibits
10 A-166 (JMP-1), pages 15 through 22, and A-167 (JMP-2), pages 17 through 20.

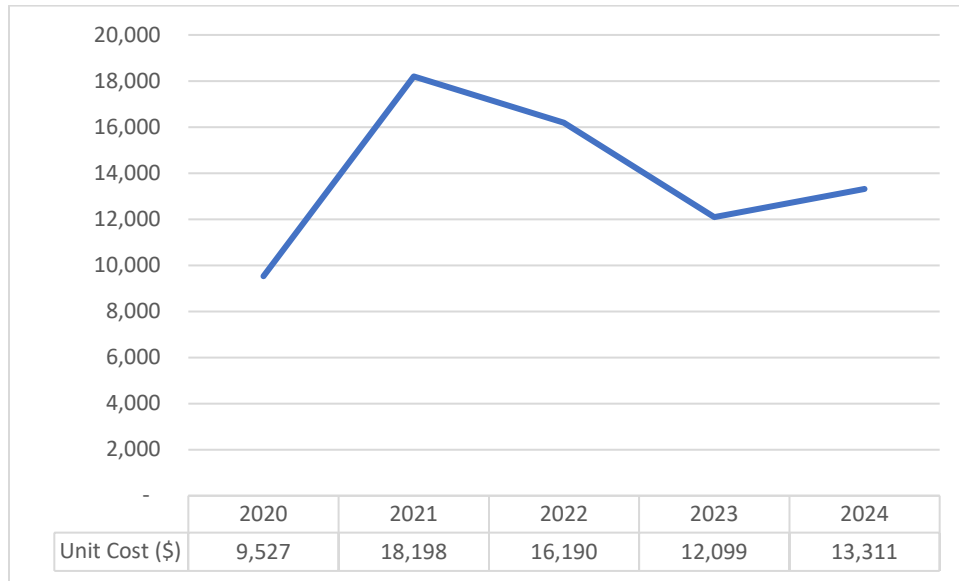
11 **Q. Please explain why some of the imminent rehabilitation projects in the LVD Lines**
12 **Rehabilitation subprogram have similar customer benefits.**

13 A. The work required for many of these projects is similar in nature and therefore some
14 projects are estimated to have similar benefits based on the reported finding and historical
15 orders of the same type. To improve secondary voltage for customers, it typically requires
16 new secondary conductor and a transformer with five customers receiving the benefit.
17 When a pole is replaced for deterioration in this subprogram, on average it benefits 242
18 customers.

19 **Q. What are the historical unit costs for the imminent rehabilitation projects in the LVD**
20 **Lines Rehabilitation subprogram?**

21 A. The historical unit costs are provided in Figure 43 below.

FIGURE 43
LVD LINES REHABILITATION INVESTMENT CATEGORY UNIT COSTS



1 **Q. Please explain any variation in unit costs over time.**

2 A. Imminent rehabilitation can vary due to variations in size and complexity of work orders.
3 In 2019, projects considered deterioration were being charged to imminent rehabilitation.
4 Primarily, this work included replacement of overhead or underground deteriorated
5 primary and secondary conductors over multiple spans due to frequent wire downs. In
6 2020, these projects were redefined to be zonal health projects, as described in the LVD
7 Lines Reliability portion of my testimony. In 2021 and 2022, the scope of the work
8 required on imminent rehabilitation was more extensive than that required in other years.
9 For example, in 2021, more underground work was completed than overhead and there
10 were more locations completed per order.

11 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
12 **subprogram?**

13 A. No. There is a wide variance among work required ranging from \$1,000 to as high as
14 \$2,100,000 per project. However, because there is a reasonable volume of units an average

unit cost could be used to analyze the projections for the overall subprogram, but not the cost of any individual project.

Resiliency

Q. What is the purpose of the Resiliency subprogram?

A. As described by Company witness Kelly and as discussed in the Reliability Roadmap, the Company's distribution objectives include building a system that is both reliable and resilient. While much of the overall Reliability Program is focused on improving reliability, this Resiliency subprogram has a particular focus on enhancing resiliency. It does this by proactively investing in strategic distribution system hardening to increase the distribution system's ability to withstand major storm events and recover from those events more quickly. As noted earlier in my direct testimony when introducing the Reliability Program, the primary purpose of Resiliency subprogram investments is to limit customer interruptions following major weather events, as opposed to solely improving blue-sky SAIDI (i.e., reliability primarily experienced during normal conditions).

Q. How does the focus of Resiliency subprogram investments compare with the Company's other investments in the Reliability Program?

A. The Company's other Reliability Program investments are primarily identified based on historical performance of portions of the system, with a focus on improving blue-sky reliability, measured in customer-outage-minutes. However, focusing only on normal weather reliability leaves parts of the system exposed to extreme weather events that result in long and costly outages and customer hardships.

Resiliency subprogram investments are meant to focus on prevention, recovery, and survivability, particularly during large events. Preventing outages is the ideal way to

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1 reduce the number of outages to customers. Each outage represents a unit of work that
2 must be completed by line workers who at times must travel from states located significant
3 distances from Michigan. If this can be avoided through prevention, the amount of time
4 spent on restoring service following a major event is considerably reduced. Likewise,
5 survivability increases the system's ability to withstand a storm system without failure.
6 Finally, recovery improvements address those times when prevention and survivability are
7 not enough, and the outage occurs. Investing in recovery reduces the duration of outages
8 that do occur.

9 **Q. Why does the Company have a standalone Resiliency subprogram?**

10 A. The Company has experienced an increasing frequency of high-speed wind gusts in its
11 service territory over the past several years which, along with system deterioration, have
12 resulted in an increase in the amount and severity of electrical outage incidents. One of
13 the recent events in August 2021 was a multi-day storm with 70 mile-per-hour wind gusts
14 that resulted in interruption to 401,000 of the Company's customers, with restoration
15 lasting up to seven days. A subsequent storm in December 2021 had peak wind gusts of
16 79 miles per hour, interrupting more than 210,000 of the Company's customers, with
17 restoration lasting up to four days. Furthermore, two ice storms in February 2023
18 interrupted approximately 400,000 customers, with restoration lasting up to eight days.
19 These interruption events—which strain the distribution system beyond previously
20 experienced levels—have increased the Company's focus on ways to mitigate major
21 weather events and led to new proposals targeting resiliency in the Company's 2022 rate
22 case in Case No. U-21224, which were further expanded in Case No. U-21389 in 2023.
23 The Company's Reliability Roadmap takes projections of worsening climate into account

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1 and correspondingly calls for additional resiliency investments to harden the system and
2 reduce customer outages even as the system faces more storms.

3 **Q. How does the Resiliency subprogram align with the Reliability Roadmap?**

4 A. The Reliability Roadmap is focused on both improving system reliability under normal
5 operating conditions and improving resiliency under extreme conditions. In the Reliability
6 Roadmap, the Company defines its strategy for LVD resiliency, based on a ramp-up of
7 LVD overhead-to-underground conversions; continuing to invest in fractionalization; and
8 continuing to install ATR loops. The Resiliency subprogram investments included in this
9 case are tied to those laid out in the Reliability Roadmap.

10 **Q. What projects, activities, and other types of work are included in the Resiliency**
11 **subprogram?**

12 A. Two primary investment categories are included in the Resiliency subprogram:
13 Fractionalization and LVD Overhead to Underground conversions. The project list
14 exhibits also include projects for the Vulnerable Communities Resiliency Plan that is
15 primarily discussed by Company witness Kelly, because these projects are primarily
16 intended to increase resiliency in the targeted communities. The project list exhibits also
17 include work related to underground services and make secondary improvements in
18 disadvantaged communities (“DACs”) under a grant from the Michigan Department of
19 Environment, Great Lakes, and Energy (“EGLE”). While the Reliability Roadmap also
20 discusses ATR Loops as a resiliency investment, they are included in the LVD Lines
21 Reliability subprogram because they also provide a substantial blue-sky SAIDI benefit.

Fractionalization

Q. Please explain what projects will be enabled by expenditures in the Fractionalization investment category.

A. Fractionalization is the practice of segmenting LVD circuits into smaller sections with fewer customers to reduce the number of customers impacted by single contingency outages and customer exposure to outages. As the distribution system has been expanded over many years to meet the requirements of connecting new customers, there are a subset of circuits with disproportionately high customer counts and overhead line exposure, resulting in reliability and resiliency challenges due to the underlying system configuration. By investing in the Fractionalization investment category, the Company will be able to:

- i. complete twelve new circuits at seven existing substations;
- ii. complete one new substation with four new circuits; and
- iii. complete purchase order milestone payments for one new mobile substation.

The mobile substation will support construction of the additional substation projects proposed in this subprogram, avoiding customer outages that would have otherwise been required.

FIGURE 44
FRACTIONALIZATION OF A SUBSTATION

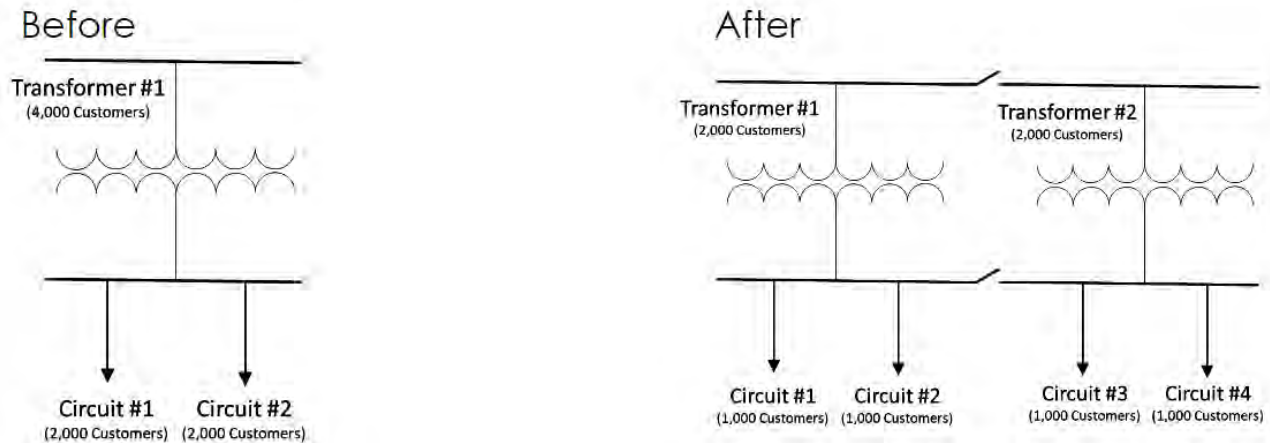
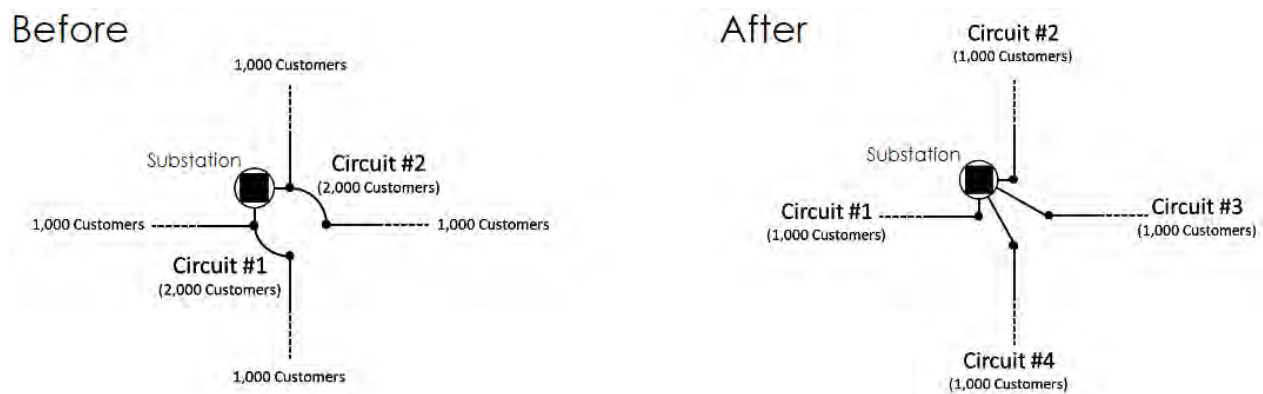


FIGURE 45
FRACTIONALIZATION OF LVD CIRCUITS

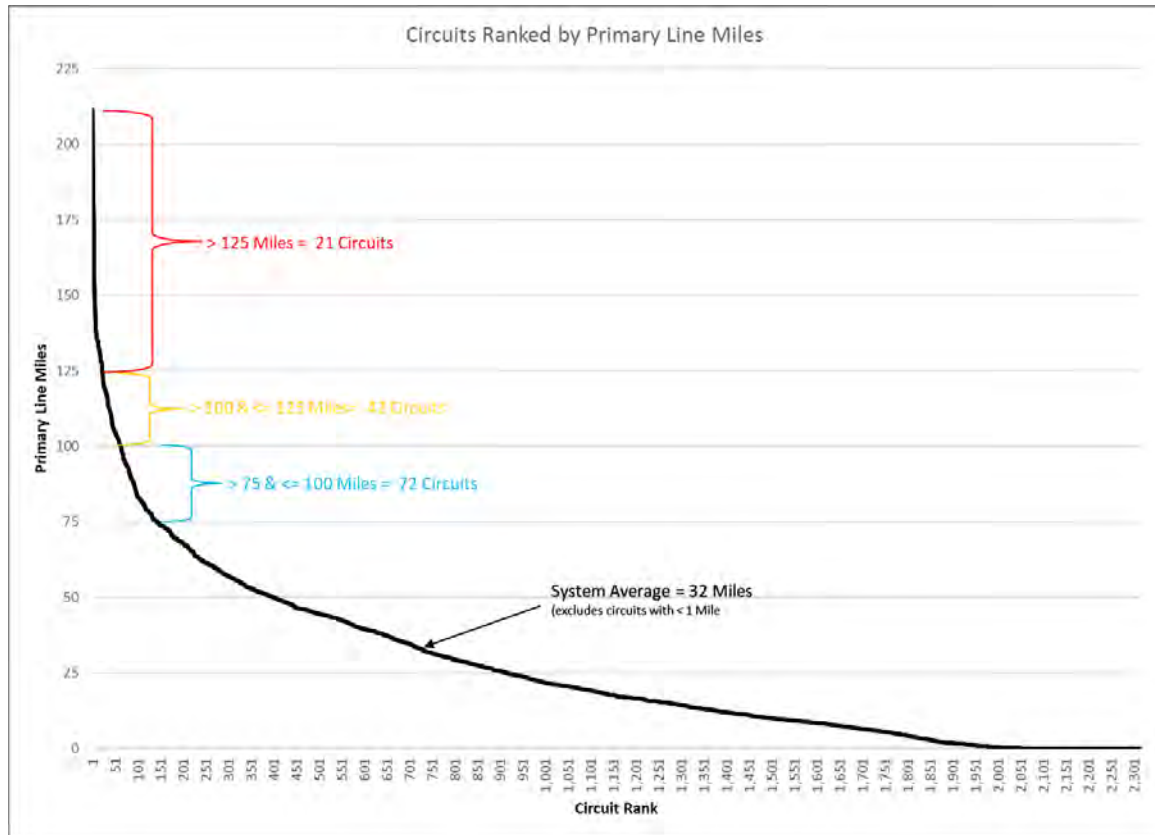


1 **Q. What criteria are used to identify the projects for the Fractionalization investment**
2 **category?**

3 **A.** The Company is targeting circuits that fall into the top tiers of circuits based upon customer
4 count and overhead line exposure. The top tiers of circuits serve more than 2,000
5 customers or more than 75 miles of overhead line exposure. As is shown in Figure 46 and
6 Figure 47, there is a small percentage of circuits that are outliers with respect to customers
7 served and miles of overhead line exposure.

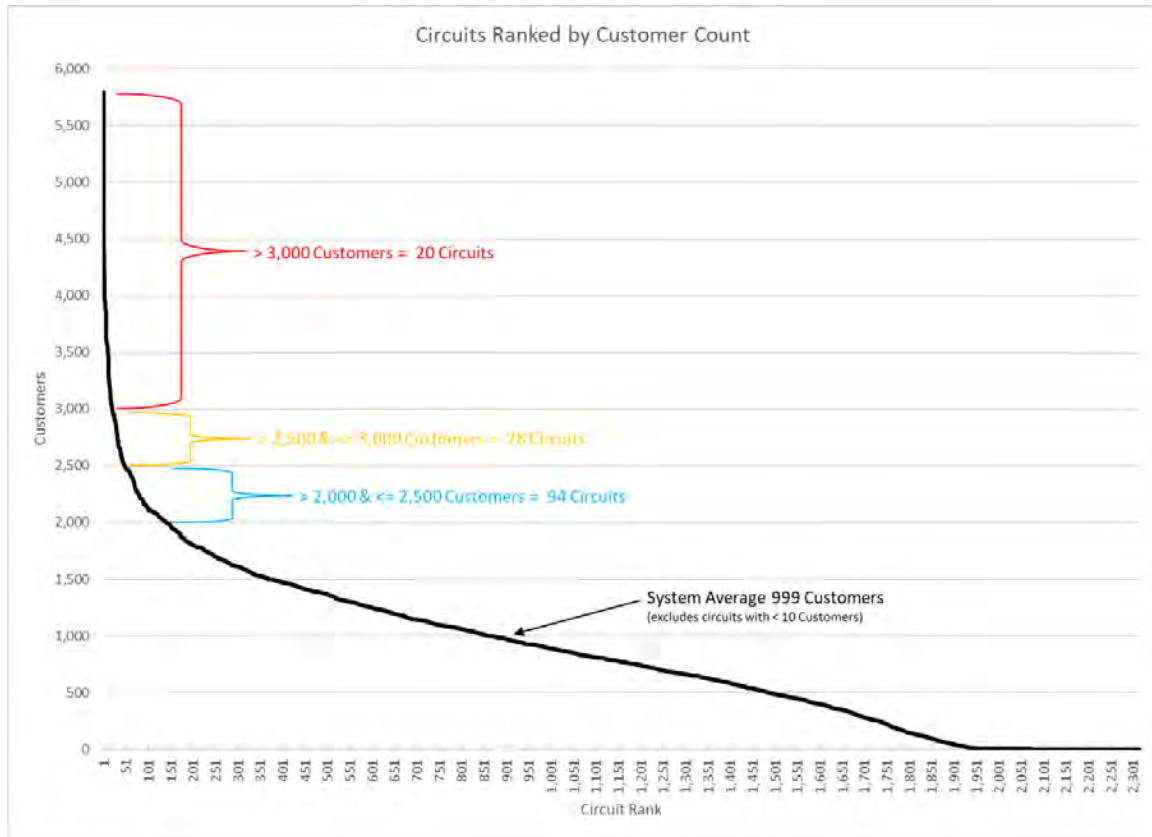
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FIGURE 46
CIRCUITS RANKED BY OVERHEAD PRIMARY LINE EXPOSURE



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FIGURE 47
CIRCUITS RANKED BY CUSTOMER COUNT



1 **Q. What has been the outage history for these top tiers of circuits?**

2 A. For the years 2019 to 2023 combined, circuit outages impacting more than 2,000 customers
3 or on circuits with more than 75 miles accounted for 848,539 customer interruptions and
4 402,278,560 customer-outage-minutes. Accordingly, these circuits can most benefit from
5 Fractionalization and the improved resiliency it will provide.

Overhead to Underground Conversions

Q. Please explain what projects will be enabled by expenditures in the Overhead to Underground investment category.

A. The Overhead to Underground investment category will fund investments in LVD lines to completely replace certain sections of overhead LVD line with underground lines and associated equipment. This investment category will not fund undergrounding of services.

Q. Why does the Company plan to underground LVD lines?

A. During large storm events, the Company can become inundated with LVD overhead line failure incidents. In the February 2023 ice storms, the Company had approximately 10,000 reported wire downs. Experience has shown that many of these incidents are precipitated by storms blowing or breaking trees that then fall upon the LVD overhead lines, resulting in outages. The Company had similar issues with the ice storm that hit northern Michigan in March and April 2025. Targeting certain overhead lines to move underground will avoid outages on these lines caused by falling trees.

Q. What criteria was used to identify the projects for the Overhead to Underground investment category?

A. The Company has used the following selection criteria for this investment category. The selected zones of the LVD system will be single-phase; have had at least one outage in the last 24 months; serve between 10 and 200 customers; be operated at one of the three standard wye voltages; not be considered for another reliability project; have a load after installation of 36% or less of the ampacity of the newly installed facilities; and be located in an area that has experienced tree- or weather-related outages.

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1 **Q. Please further explain these criteria choices.**

2 A. Single-phase was selected due to its lower cost, the typically limited number of customers
3 who would be negatively impacted by an underground line outage, and being least
4 susceptible to above average load growth. LVD protective zones with at least one outage
5 in the last 24 months were selected so that there would be a more immediate reliability
6 benefit. Limiting the customers served by the zone to between 10 and 200 ensures that the
7 project provides benefits to more than a few customers, while limiting the impact of any
8 outage on the underground facilities. Underground conversion of only the three standard
9 wye voltages ensures that additional costs are neither initially incurred on the additional
10 equipment to accommodate delta configurations nor the conversion cost to a standard wye
11 voltage later. Similarly, selecting zones that are not considered for another reliability
12 project avoids duplication of efforts. Ensuring that the new underground facilities are
13 loaded to 36% or less of their ampacity provides for typical load growth without needing
14 to replace the facility before end-of-life. Finally, underground conversions in areas that
15 have experienced tree and weather-related outages helps to minimize future forestry
16 clearing costs.

17 **Q. Have any of the selection criteria changed since the Company's pilot as proposed in**
18 **Case No. U-21389.**

19 A. In the pilot in Case No. U-21389, the Company selected zones serving between 10 and 100
20 customers, but the upper limit has been increased to 200 customers. The pilot also focused
21 on zones with CAIDI of over 600, and this constraint has been removed. Additionally, the
22 pilot focused on zones with dense tree cover; as noted above, this criterion has been

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1 redefined to focus on zones that have recently experienced significant tree and weather-
2 related outages.

3 Furthermore, as discussed by Company witness Kelly, the pilot determined that
4 undergrounding projects would have higher costs when in densely populated areas or areas
5 that require significant boring work, and lower costs in more lightly populated areas where
6 trenching or plowing is possible. The Company's projects in the instant case were
7 identified based on being able to take advantage of locations that would have lower unit
8 costs based on these lessons learned.

9 **Q. Do these selection criteria mean that all circuits or zones meeting these selection**
10 **criteria will ultimately be converted to underground?**

11 A. No, not necessarily. The purpose of the selection criteria is to narrow the Company's total
12 population of LVD circuits down to a more manageable list so that it can identify locations
13 where undergrounding is most justified. In the instant case, the Company is only seeking
14 cost recovery related to the projects identified in Exhibits A-166 (JMP-1) and A-167
15 (JMP-2).

16 **Resiliency: Overall Investment and Benefits**

17 **Q. What is the Company's projected test year spending level, for which it is requesting**
18 **cost recovery for the Resiliency subprogram?**

19 A. The Company is requesting recovery of additional resiliency capital expenditures in the
20 amount of \$21,194,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 20,
21 column (k), and \$35,765,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 20,
22 column (l).

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1 **Q. Please explain how the capital expenditures projected for the test year for this**
2 **subprogram will be allocated across the two investment categories.**

3 A. The Company is projecting unit and capital expenditures in the test year for each
4 investment category as identified in Figure 48 below.

FIGURE 48
RESILIENCY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Fractionalization	\$15,826,000	8	\$11,647,000	3
Overhead to Underground	\$1,250,000	1.4	\$20,000,000	50
EGLE - MIEJ Undergrounding Secondary and Services	\$4,118,000	7	\$4,118,000	9
Total	\$21,194,000		\$35,765,000	

5 **Q. Please identify the projects that will be completed in the Resiliency subprogram.**

6 A. The Company has identified projects for the bridge period, listed in Exhibit A-166 (JMP-1),
7 page 28, and for the test year, listed in Exhibit A-167 (JMP-2), page 21. Projected project
8 costs were developed considering estimated costs for materials and labor and the
9 Company's previous experience performing similar projects. This exhibit also identifies
10 the location and benefits of the projects.

11 **Q. Are there any projects that span multiple years?**

12 A. Yes. The Backus, Greenwood, and Mobile 27 projects, listed in Exhibit A-166 (JMP-1),
13 page 28, lines 2 through 4, will span multiple years due to mobile substation purchase order
14 milestone payments and construction scheduling. The Eagle and Mobile 27 projects, listed

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in Exhibit A-167 (JMP-2), page 21, lines 30 and 31, will span multiple years due to mobile substation purchase order milestone payments and construction scheduling.

Q. How were the proposed Fractionalization projects identified?

A. The proposed Fractionalization projects will address four of the 40 highest customer count circuits, and four of the 40 highest line exposure circuits. Figure 49 identifies the pre-investment and post-investment configurations for these circuits benefitting more than 28,000 customers. Additional projects shown in Exhibit A-167 (JMP-2) will also address circuits with over 2,000 customers or with line exposures over 75 miles of exposure.

FIGURE 49
FRACTIONALIZATION PROJECTS STATISTICS

Resiliency Projects	Pre-Investment Configuration				Post-Investment Configuration (Estimate)				Benefit Cust-Min
	Substation	Circuit	Customers	Total Miles	Substation	Circuit	Customers	Total Miles	
Backus Substation	Backus	Springbrook	5,587	116	Backus	Springbrook	3,564	74	217,331
	Backus	Maple Valley	1,001	60	Backus	Maple Valley	1,001	60	
					Backus	New Circuit 3	1,250	27	
					Backus	New Circuit 4	773	15	
Bennington Substation	Bennington	Manitou	759	53	Bennington	Manitou	759	53	76,750
	Bennington	Grand River	1,390	114	Bennington	Grand River	852	63	
					Bennington	New Circuit 3	538	51	
Eagle Substation	Chicago	Chicago	1892	28	Chicago	Chicago	1,892	28.077	249,309
	Chicago	Pinebrook	2650	33	Chicago	Pinebrook	1,987	25.161	
	Hager Park	Wellington	948	31	Hager Park	Wellington	553	13.885	
	Hager Park	Hager Park	3,735	58	Hager Park	Hager Park	968	31.701	
	Rosewood	Pioneer	1,171	13	Rosewood	Pioneer	1,171	12.681	
	Rosewood	Cottonwood	2,083	22	Rosewood	Cottonwood	2,083	21.844	
	Rosewood	Lamplighter	2,241	24	Rosewood	Lamplighter	1,923	20.302	
	Van Buren	Van Buren	1,871	25	Van Buren	Van Buren	1,316	17.27	
	Van Buren	Moss Lake	375	10	Van Buren	Moss Lake	375	9.58	
	Van Buren	Rush Lake	1,516	36	Van Buren	Rush Lake	680	20.943	
					Eagle	New Circuit 1	1,610	24.272	
					Eagle	New Circuit 2	1,051	16.462	
					Eagle	New Circuit 3	1,838	21.407	
					Eagle	New Circuit 4	1,035	14.923	
Greenwood Substation	Alger	Skidway	4,093	131	Alger	Skidway	613	60	361,337
	Alger	Forest Lake	1,647	117	Alger	Forest Lake	1,034	58	
	Greenwood	Rau Road	1,055	87	Greenwood	Rau Road	912	87	
	Greenwood	Indian Lake	1,240	95	Greenwood	Indian Lake	1,240	83	
					Greenwood	New Circuit 3	4,236	142	
Whittemore Substation	Whittemore	M-65	1,654	135	Whittemore	M-65	723	64	107,599
	Whittemore	Sand Lake	2,300	87	Whittemore	Sand Lake	1,907	48	
					Whittemore	New Circuit 3	457	40	
					Whittemore	New Circuit 4	867	70	

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1 **Q. Why does the projected investment level for Overhead to Underground vary between**
2 **the bridge period and the test year?**

3 A. In Case No. U-21389, the Commission approved approximately ten miles of
4 undergrounding projects as part of a proposed pilot. In Case No. U-21585, the Company
5 proposed to expand that pilot and continue undergrounding additional circuits, but the
6 Commission did not approve this proposal since pilot results were not yet available.
7 Because of this, the Company is not doing any new major undergrounding work in the
8 bridge period in this case. The projects included in the bridge period consist of one project
9 that was approved as part of the pilot in Case No. U-21389 that is still being finished in the
10 bridge period (“TAWAS/TAWAS/482”). It also includes one project (“SQUIRE
11 HILL/EDGEWATER/775”) that was proposed in Case No. U-21585. The Company
12 started work on this project at the beginning of March 2025, coincident with the test year
13 in Case No. U-21585, before the Commission issued its final Order in that case. Because
14 the Company had already commenced work, and because the project serves a vulnerable
15 community, the Company will complete this work in the bridge period to deliver benefits
16 to these customers.

17 As Company witness Kelly discusses, the Company now has the results of the pilot,
18 has assessed those results, and now plans to move forward with further undergrounding
19 work beginning in the test year. Exhibit A-167 (JMP-2), page 21, lists these new
20 undergrounding projects.

1 **Q. What is included in the projects in Exhibits A-166 (JMP-1) and A-167 (JMP-2) related**
2 **to “undergrounding of services and secondary improvements in DACs?”**

3 A. The Company received a grant from EGLE under Section 40101(d) of the Infrastructure
4 Investment and Jobs Act, that is intended to underground secondary in disadvantaged
5 communities, and these projects are where the Company will execute this work. Note that
6 this work is separate from overhead to underground conversions, which focus on primary
7 circuits, not on secondary.

8 **Q. What is included in the projects in Exhibit A-167 (JMP-2), page 22, related to**
9 **“Resiliency – MIEJ Hardening?”**

10 A. These projects represent the test year work for the Company’s Vulnerable Communities
11 Resiliency Plan, as discussed in detail by Company witness Kelly.

12 **Q. What benefits will customers realize through the Company completing work, at the**
13 **requested spending level, in the Resiliency subprogram?**

14 A. The additional resiliency spending will provide direct and immediate reliability benefits to
15 customers connected to the projects. These projects will better prepare the LVD system
16 for the increasing frequency and severity of wind gusts and storms. The LVD system is
17 most at risk of experiencing failures from severe weather. Therefore, the resiliency
18 spending will reduce the quantity of outages or the extent of the LVD system impacted
19 during an outage.

20 **Q. How will the identified Fractionalization projects improve resiliency?**

21 A. Fractionalization will address recovery and prevention by dividing the system into smaller
22 portions, reducing the number of customers experiencing an outage for a single failure; and

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1 reducing the customers' miles of exposure to overhead line outages, preventing outages to
2 customers that would have otherwise been interrupted.

3 Fractionalization will also provide operational switching opportunities, allowing
4 for improved fault isolation and faster restoration of customers prior to the completion of
5 repairs, also enabling a quicker recovery from the outage. An ancillary benefit of
6 Fractionalization is increased system capacity, available for both increased load and
7 renewable resource hosting capacity.

8 **Q. How will the identified Overhead to Underground projects improve resiliency?**

9 A. Investing in conversion of LVD overhead lines to underground will increase both
10 survivability and prevention. Underground LVD lines are expected to survive nearly all
11 tree-caused and ice-caused failures preventing outages during major storm events. The
12 Company's experience has shown that the greatest cause of interruptions on the LVD
13 system is due to trees. Winter storms with ice also cause outages during major events.
14 EPRI research and the WEC Energy Group have found that undergrounding of single-
15 phase laterals is highly effective at hardening the distribution grid from storm damage and
16 reducing interruptions.

17 The picture in Figure 50 provides an example of the types of incidents that can be
18 avoided if lines are placed underground. In this instance, a tree has fallen on the line in an
19 area that will be difficult for crews to reach, because it is located in the woods with snow
20 cover.

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FIGURE 50
TREE ON OVERHEAD SINGLE-PHASE PRIMARY LINE



- 1 **Q. Please summarize the benefits customers will realize through the Company**
2 **completing work, at the requested spending level, in the Resiliency subprogram.**
- 3 A. With fewer line miles for line workers to patrol and repair to restore service due to
4 fractionalization and with fewer LVD line failures overall due to overhead-to-underground
5 conversions, there will be less restoration work time required, providing more time for line
6 workers to complete other restoration work, resulting in a quicker restoration overall.
7 Simply put, faster restoration and recovery from an event result in shorter electric
8 interruption durations, benefiting all storm-impacted customers.

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The direct customer benefits for the projects are identified in the Benefit Type and Benefit columns of Exhibits A-166 (JMP-1), page 28, and A-167 (JMP-2), page 21. Types of benefits identified on the exhibits, and summarized in Figure 51, include:

FIGURE 51
RESILIENCY BENEFITS SUMMARY

Investment Category	Benefit Categories	Bridge Period	Test Year
Fractionalization	Customer-outage-minutes avoided	1,214,132	76,750
Overhead to Underground	Customer-outage-minutes avoided	-	2,040,235
EGLE - MIEJ Undergrounding Secondary and Services	Customers	193	179

Capacity Program

Q. What portion of the Capacity Program will your testimony discuss?

A. The Capacity Program is designed to ensure the distribution system can serve the electric peak demand, keep the system within acceptable voltage ranges, and support the Company's CVR subprogram. Company witness Kelly introduces and further discusses this program. This testimony will focus on the LVD subprograms:

- (i) LVD Lines Capacity;
- (ii) LVD Transformers Capacity;
- (iii) LVD New Business Capacity; and
- (iv) CVR.

Projected spending is explained in greater detail in the subprogram sections below. The LVD Transformers Capacity subprogram is part of a single-purchase plan, and is covered in the Meters and Transformers section of this testimony.

1 **Q. Does the Company use AMI data in its planning process?**

2 A. Yes. The Company's AMI system collects the total kWh delivered, total kWh received,
3 the total kilovolt-amperes-reactive-hours ("kvarh") delivered, total kvarh received, and
4 average voltage over the meter reading interval, which can be hourly or every 15 minutes,
5 depending on the meter. The Company uses AMI data to identify the frequency and length
6 of customer outages, and that information is used to inform and focus distribution planning
7 Additionally, kVA values in the Customer Loads database are derived from monthly AMI
8 billing consumption data, and used by the Company's distribution power flow model,
9 CYME, for purposes of modeling load at the customer level. The Company uses CYME⁸
10 power engineering software to analyze loading on the distribution system. Company
11 witness Scott A. McPhail's testimony discusses a Load Flow Tool Upgrade that is needed
12 to enable the full time-series benefits of AMI datasets in CYME.

13 **Q. Does the Company consider Non-Wires Solutions ("NWS") in its planning processes?**

14 A. Company witness Kelly discusses the Company's current position on NWS in his direct
15 testimony. The Company is developing a new NWS pilot in 2025 that it plans to submit
16 outside of the regular rate case process in the Commission's expedited pilot process.

17 **LVD Lines Capacity**

18 **Q. Please explain what capital projects, activities, and other types of work will be enabled**
19 **by expenditures in the LVD Lines Capacity subprogram.**

20 A. Capital investments in the LVD Lines Capacity subprogram address and reduce overload
21 risk on components of the LVD lines system. All components on the system have a rating
22 for their maximum designed load, and while any individual component can withstand

⁸ CYME is the trade name of the software, which was previously named Chinh Yvan Micro Engineering.

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1 loading to greater than 100% of this level for a short time, overloads that are too long or
2 too frequent lead to deterioration and increased risk of failure. Investment in this
3 subprogram responds to risks that already exist due to load growth or load shifting from
4 one area of the system to another. These investments fund critical projects to address
5 capacity loading issues in accordance with planning criteria and to address new distributed
6 load additions to ensure that the LVD system can accommodate projected distribution
7 loads. Investments in this subprogram are divided into two categories: equipment upgrades
8 and lines capacity projects associated with substation projects.

9 **Q. Why does the Company invest in LVD Lines Capacity projects to upgrade or replace**
10 **overloaded lines and equipment?**

11 A. The Company upgrades or replaces overloaded lines and equipment to reduce reliability
12 and safety risks, including equipment failure; nuisance disruptions of sectionalizing
13 devices (e.g., fuse links melting); potential oil spills; equipment heating with a potential
14 risk of fire; inadequate voltage to downstream customers; and conductor melting or sagging
15 creating a public safety hazard of potential contact. Additionally, fixing overload risks on
16 the LVD system better positions the system to accommodate future growth of EV charging,
17 heating electrification, and other customer adoptions of new technologies.

18 **Q. Why does the Company invest in LVD Lines Capacity projects associated with**
19 **substation capacity projects?**

20 A. Substations are part of the backbone infrastructure of the electric distribution network;
21 therefore, LVD Lines Capacity projects must be completed to reduce the risk of failure due
22 to substation equipment reaching capacity limits. When an increase in the transformer
23 equipment size is not a reasonable alternative, other solutions implemented may include a

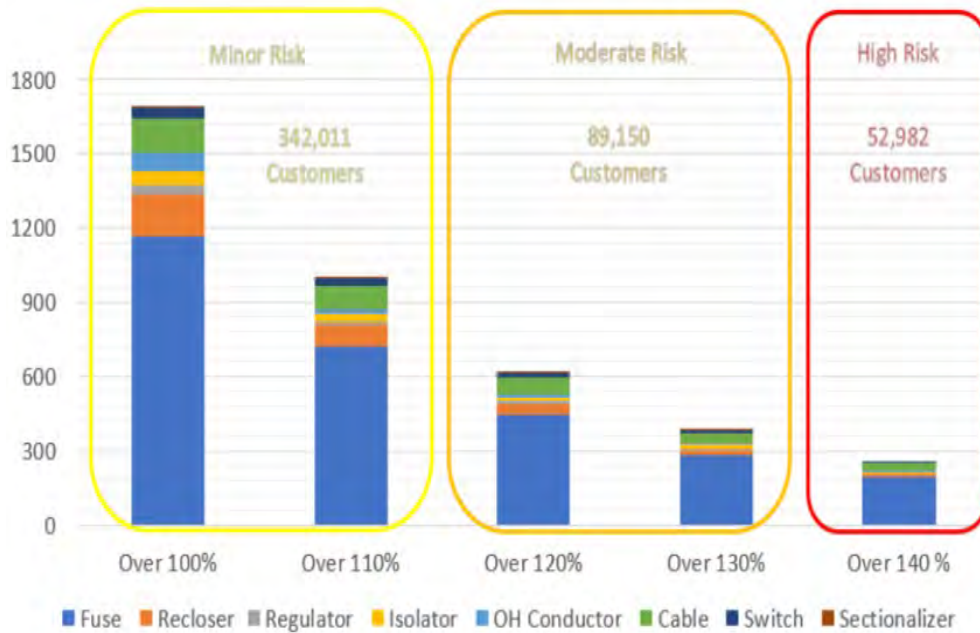
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1 new substation with LVD line upgrades or line extensions that transfer customers to other
2 nearby circuits to reduce the load on the existing substation equipment.

3 **Q. How are projected LVD Lines Capacity subprogram expenditures aligned with the**
4 **Reliability Roadmap?**

5 A. The projected expenditures are directly tied to the LVD Overload Risk Reduction plan
6 outlined in the Reliability Roadmap. As the LVD Overload Risk Reduction plan describes,
7 the Company has a significant population of assets that are loaded to greater than 100% of
8 their rating. In the highest-risk situations, assets are loaded to much greater levels than
9 their respective ratings. In the Reliability Roadmap, the Company outlined a plan to
10 address these overload issues; while the bridge period investments in this case are aligned
11 with levels approved by the Commission in Case No. U-21585, the test year investments
12 represent the Company's continuation of its efforts to execute this plan at levels defined in
13 the Reliability Roadmap. The plan defined in the Reliability Roadmap is intended to
14 address all components overloaded beyond 100% of their rating in order to eliminate
15 overload-caused outages on the LVD system.

FIGURE 52
QUANTITY OF COMPONENTS LOADED TO SPECIFIC PERCENTAGES, 2024



Q. Did the Company consider any alternatives to this approach?

A. Yes. The Company could continue to allow assets on its system to be regularly overloaded, but this simply magnifies risk to the system, especially in a situation in which summer temperatures and, therefore, summer cooling load continue to increase. It is more prudent to address overload risks proactively. With that in mind, the Company does work to develop projects that will best address overload risk from among available alternatives. Projects in this subprogram are developed by the LVD circuit planners to address the identified capacity issues. They identify the best method of improving the issue using the various approaches described above. The Company prioritizes capacity projects based primarily on overload level, addressing the highest overloads prior to lower overloads, with adjustments made for other factors such as historical reliability, customer mix, and safety impact.

1 **Q. How does the Company identify capacity issues that would require an LVD Lines**
2 **Capacity project?**

3 A. The Company's project selection follows three steps:

4 (i) considering peak loads;

5 (ii) comparing peak loads to failure criteria; and

6 (iii) ranking components by their percentage of overload.

7 **Q. What is the significance of considering peak load in this subprogram?**

8 A. All planning activities in this subprogram are based on projected peak load conditions,
9 which is when capacity is most challenged. The Company uses normal or continuous
10 ratings for peak load conditions, due to the heightened risk of equipment failure or
11 degradation when operating above the capability rating. The loadings on equipment are
12 established by the manufacturer or by a recognized industry source such as the Institute of
13 Electrical and Electronics Engineers, and specify the optimal operation of the equipment
14 based on the capability characteristics of the components. The specific evaluation of each
15 piece of equipment depends on its use. For example, equipment using oil is rated based on
16 a temperature limit not to be exceeded. If that operating temperature is exceeded, then the
17 equipment can start to break down and possibly lead to a shorter lifespan. Other equipment
18 has a defined set of characteristics that, when taken beyond the manufacturer
19 specifications, can lead to a change in characteristics of the material, altering its strength
20 and durability.

1 **Q. Please describe the Company's power flow study process to evaluate the LVD**
2 **system's ability to handle peak loads.**

3 A. The Company evaluates the LVD system using CYME, an industry-standard power flow
4 software, to perform a power flow analysis. CYME uses load information from two
5 databases to perform power flow studies: the Feeder Demand database and the Customer
6 Loads database. The Feeder Demand database provides the maximum amperage
7 experienced on the circuit with data from substation metering equipment. The Customer
8 Loads database uses customer meter data. The CYME power analysis compares the Feeder
9 Demand load at the substation to the Customer Load distributed across the circuit to
10 determine power flow, voltages, and system protection needs. This analysis is performed
11 on present and future states of the system. This process identifies overloaded distribution
12 equipment and instances of unacceptably low or high voltage during system peak load
13 conditions.

14 **Q. How often does the Company conduct these power flow studies?**

15 A. The Company annually evaluates loading on its LVD distribution equipment, using
16 CYME, for capacity planning purposes. Additionally, studies are completed throughout
17 the year to address emergent issues such as load transfers, generator interconnections, new
18 customer load additions, and reliability failures.

19 **Q. After the power flow study is performed, how does the Company determine if an LVD**
20 **Lines Capacity project is required?**

21 A. Capacity planning criteria requires that a component of the distribution system have a
22 projected load higher than its capacity, based on Company standards for capacity, before
23 developing a potential capacity project. At present, this requires that a component of the

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1 distribution system experience a load more than its capacity a minimum of one year prior
2 to a capacity project being initiated.

3 **Q. What other factors does the Company consider when determining if an LVD Lines**
4 **Capacity project is required?**

5 A. Previous year loadings and future customer growth are considered when projecting future
6 loadings. While most equipment has emergency ratings that enable higher capacity for
7 short durations, these are not considered during capacity planning, since loading at these
8 higher levels results in degradation and eventual failure.

9 **Q. Has the Company considered the impact the adoption of EVs may have on its LVD**
10 **system?**

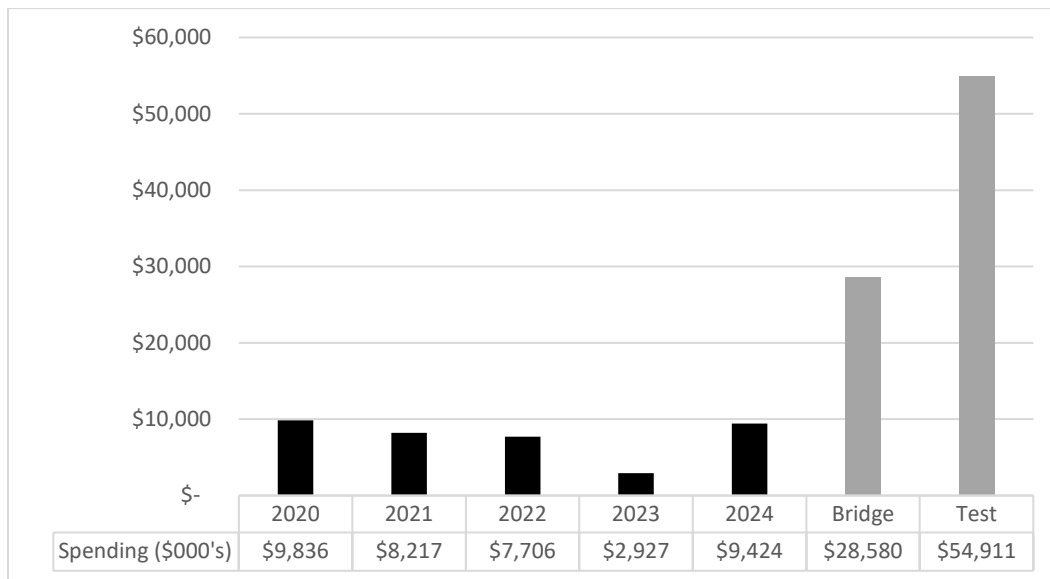
11 A. Yes. As the Company continues to support EV growth as described by Company witness
12 Jeffrey A. Myrom, the first step to understanding LVD system impact is to predict when
13 and where EVs will charge. To that end, the Company has conducted an EV propensity
14 study in the past to consider potential concentration of at-home residential charging on
15 certain circuits, which was discussed in detail by Company witness Donald A. Lynd in
16 Case No. U-21585. To date, this is still the most recent propensity study conducted by the
17 Company. Note that larger scale charging is expected to be a spot load and be addressed
18 through the Company's LVD Lines New Business and LVD New Business Capacity
19 subprograms. Company witness McPhail discusses the need for a Load Flow Tool
20 Upgrade to enhance the Company's ability to forecast and simulate the impacts of EVs and
21 other customer technology adoption on the distribution system. This initiative is necessary
22 to integrate EV propensity studies, such as the one mentioned above, with the CYME
23 software as a regular and repeatable step in the capacity planning process.

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1 **Q. What are the Company's projected bridge period and test year spending levels, for**
2 **which it is requesting cost recovery, in the LVD Lines Capacity subprogram?**

3 A. The Company is projecting LVD Lines Capacity capital expenditures of \$28,580,000 in
4 the bridge period, as shown in Exhibit A-113 (MPK-3), line 22, column (k), and
5 \$54,911,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 22, column (l). The
6 Company's historical actual spending in the LVD Lines Capacity subprogram, along with
7 the bridge period and test year projections, are shown in Exhibit A-113 (MPK-3), line 22,
8 and below in Figure 53. As discussed above, the increase in spending in the bridge period
9 is aligned with what the Commission approved in Case No. U-21585, and the further
10 increase in the test year is aligned with the Company's Reliability Roadmap goal of
11 addressing all assets loaded beyond 100% of their ratings.

FIGURE 53
LVD LINES CAPACITY SUBPROGRAM EXPENDITURES



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1 **Q. Please explain how the capital expenditures projected for the bridge period and the**
2 **test year for this subprogram will be allocated across the two investment categories.**

3 A. The Company is projecting unit and capital expenditures in the bridge period and test year
4 for each investment category as identified in Figure 54.

FIGURE 54
LVD LINES CAPACITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Overloaded equipment upgrades	\$21,365,000	125	\$53,103,000	278
Lines capacity projects assoc. w/ substation work	\$7,215,000	12	\$1,808,000	3
Total	\$28,580,000		\$54,911,000	

5 **Q. Please identify the projects that will be accomplished with the requested spending**
6 **level in the LVD Lines Capacity subprogram.**

7 A. The Company has identified projects for the bridge period, listed in Exhibit A-166 (JMP-1),
8 pages 29 through 31, and for the test year, listed in Exhibit A-167 (JMP-2), pages 23
9 through 27. The Company developed the projected costs of the projects in these exhibits
10 considering estimated costs for materials and labor, and the Company's previous
11 experience performing similar projects. These exhibits also identify the location and
12 benefits of the projects.

13 **Q. Please explain the year-over-year historical variation in spending in this subprogram.**

14 A. In 2019, significant increases in LVD New Business, Asset Relocations, and Demand
15 Failures work, as discussed elsewhere in my direct testimony, required the Company to
16 shift resources away from LVD Lines Capacity to focus on work within those subprograms.
17 A similar shift of resources was required in 2023.

1 **Q. What benefits will customers realize through the Company completing work, at the**
2 **requested spending level, in the LVD Lines Capacity subprogram?**

3 A. This subprogram prevents future failures that would increase SAIDI if they occurred. The
4 investments made to upgrade overloaded assets and alleviate voltage issues increase the
5 longevity of the equipment and prevent service issues and interruptions to customers while
6 improving employee and public safety. The benefits of each project in this subprogram
7 are identified in the Benefit Type and Benefit columns of Exhibit A-166 (JMP-1), pages 29
8 through 31, and for the test year, listed in Exhibit A-167 (JMP-2), pages 23 through 27.

9 **Q. Does an average unit cost accurately reflect the expected spend per project for this**
10 **subprogram?**

11 A. No. Average unit cost is not a good measure of spend to predict the cost of an individual
12 project in this subprogram. There is a wide variance among work required, ranging from
13 \$2,000 for a protective device upgrade to \$2,000,000 for a multi-mile voltage conversion
14 project.

15 **LVD New Business Capacity**

16 **Q. Please explain what projects, activities, and other types of work will be enabled by**
17 **expenditures in the LVD New Business Capacity subprogram.**

18 A. Equipment and lines need to be added or upgraded for new customers or to maintain
19 adequate service to existing customers when they increase their load beyond existing
20 capacity. Projects in the LVD New Business Capacity subprogram are generally similar
21 in scope to projects in the LVD Lines Capacity subprogram. Because work in this
22 subprogram is driven by customer requests, the Company does not plan or prioritize
23 projects far in advance in this subprogram.

1 **Q. Is there a specific timeframe that the Company needs to complete a New Business**
2 **Capacity project?**

3 A. Yes. Each new business capacity project needs to be constructed on the same timeframe
4 as the customer load addition that is driving the project to avoid overload of the LVD
5 system. Accordingly, the Company has little latitude on whether to delay or defer these
6 new business capacity projects.

7 **Q. What benefits will customers realize through the Company completing work, at the**
8 **requested spending level, in the LVD New Business Capacity subprogram?**

9 A. As with other Capacity subprograms, work in the LVD New Business Capacity
10 subprogram ensures the reliable distribution of electricity to customers by preventing
11 overloads on the system that can cause outages and poor voltage service. The LVD New
12 Business Capacity subprogram provides the added benefit of allowing customers,
13 particularly in the commercial and industrial (“C&I”) sectors, to expand their activities and
14 drive economic growth in Michigan. Although spending in the LVD New Business
15 Capacity subprogram is not explicitly tied to the LVD Overload Risk Reduction plan in the
16 Reliability Roadmap, work in this subprogram does increase the capacity of the system,
17 which thereby reduces the risk of future overloads while accommodating new customer
18 loads.

19 **Q. Please identify the projects that will be accomplished with the requested spending**
20 **level in the LVD New Business Capacity subprogram.**

21 A. The Company has identified projects for the bridge period, which are listed in Exhibit
22 A-166 (JMP-1), pages 32 through 36. Due to the nature of the New Business Capacity
23 subprogram, only projects known in advance are listed. Accordingly, the bridge period list

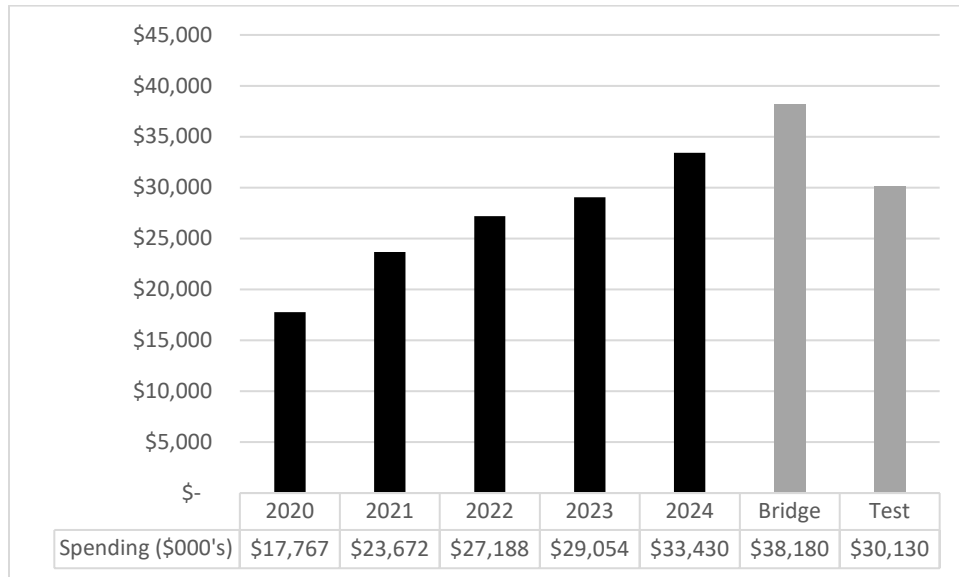
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1 is not a complete list of all work that will be performed, and the Company is not yet aware
2 of specific projects for the test year. The Company developed the projected costs of the
3 projects in this exhibit considering estimated costs for materials and labor, and the
4 Company's previous experience performing similar projects.

5 **Q. What are the Company's projected bridge period and test year spending levels, for**
6 **which it is requesting cost recovery, in the LVD New Business Capacity subprogram?**

7 A. The Company is projecting LVD New Business Capacity capital expenditures of
8 \$38,180,000 in the bridge period, as shown in Exhibit A-113 (MPK-3), line 25, column (k),
9 and \$30,130,000 in the test year, as shown in Exhibit A-113 (MPK-3), line 25, column (l).
10 The Company's historical actual spending in the LVD New Business Capacity
11 subprogram, along with the bridge period and test year projections, are shown in Exhibit
12 A-113 (MPK-3), line 25, and below in Figure 55.

FIGURE 55
LVD New Business Capacity Subprogram Expenditures



1 **Q. How did the Company develop its projected expenditures in this subprogram?**

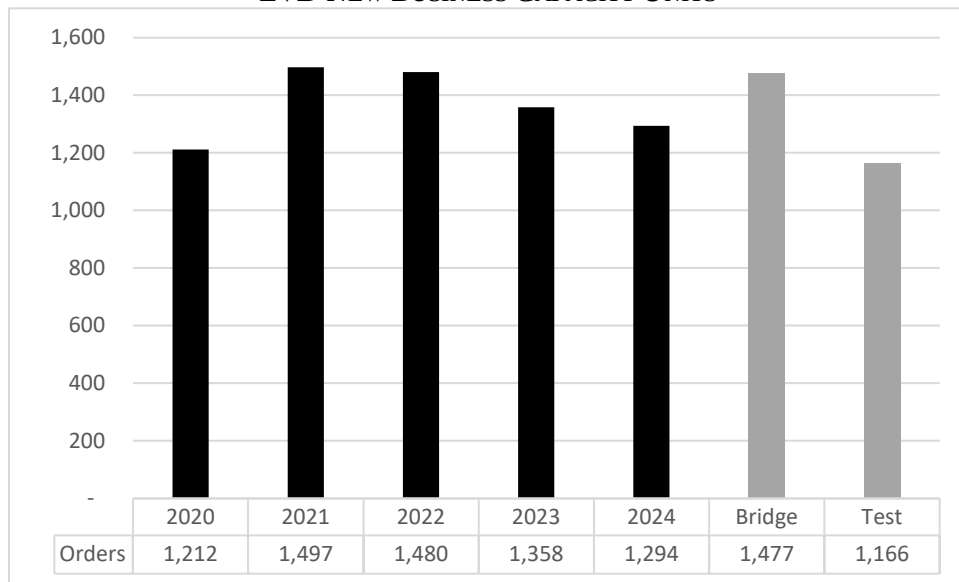
2 A. LVD New Business Capacity work is based on customer-driven needs, therefore the
3 Company bases its spending projections on historical actual spending with adjustments for
4 observed trends. The Company has been experiencing an increase in spending on LVD
5 New Business Capacity in recent years. Note that the projected bridge period and test year
6 investment levels represent a modest increase from the five-year average, but they are on
7 par with the Company's 2023 actual investment level and lower than the 2024 actual level
8 (on an annual basis). The number of new business capacity orders per year increased from
9 1,170 in 2019 to an average of 1,377 over the last three years. Considering that fewer new
10 business connections are expected, as described in the LVD Lines New Business section
11 of testimony, and overloads will be reduced through the increased investment in the LVD
12 Lines Capacity subprogram, the number of orders in this subprogram is expected to decline.
13 However, there is not a one-to-one relationship to the LVD Lines New Business
14 subprogram because need in the LVD New Business Capacity subprogram is driven

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1 primarily by larger loads, such as C&I customers. The Company anticipates future per
2 order costs for the bridge period and test year to be similar to costs experienced in 2023
3 and 2024. The Company projects it will complete 1,477 orders in this subprogram in the
4 bridge period.

5 The spending amount for the test year was determined based on the anticipated
6 number of orders in the test year. The Company projects it will complete 1,166 orders in
7 this subprogram in the test year. The historical and projected number of orders is shown
8 in Figure 56 below.

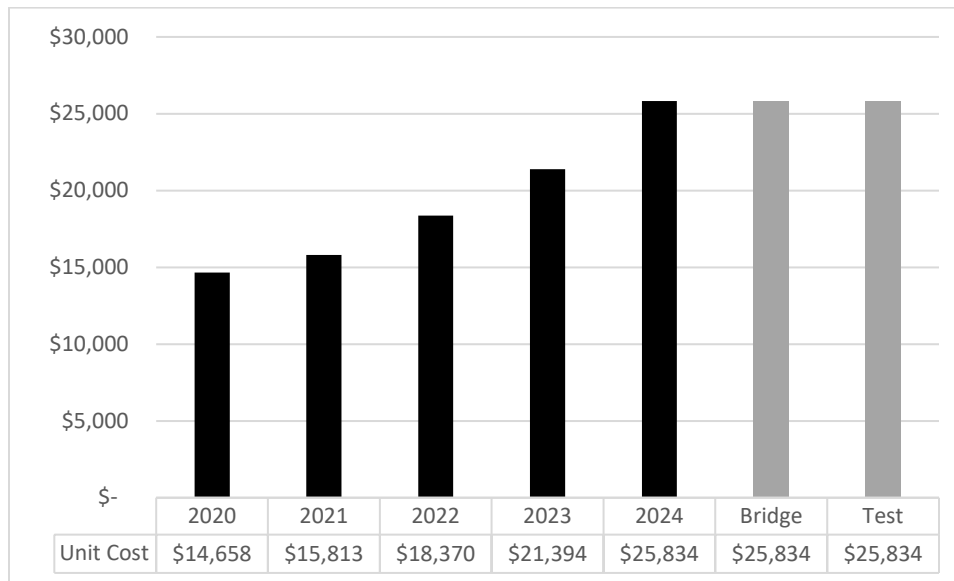
FIGURE 56
LVD NEW BUSINESS CAPACITY UNITS



9 **Q. What are the historical unit costs for the LVD New Business Capacity subprogram?**

10 **A.** The historical and projected unit costs of LVD New Business Capacity orders are provided
11 in Figure 57 below. Unit costs in this subprogram have increased due to rising material
12 costs such as cable and poles as discussed in the LVD Lines New Business section of my
13 testimony.

FIGURE 57
LVD NEW BUSINESS CAPACITY HISTORICAL UNIT COSTS



1 **Q. Does an average unit cost accurately reflect the expected spending per project for this**
2 **subprogram?**

3 A. Yes, for the overall subprogram. There is a variance of costs among the different projects
4 required ranging from \$1,000 for a protective device upgrade to as high as \$1,100,000 for
5 the LVD work associated with the construction of a new substation. However, because of
6 the volume of units an average unit cost can be used to develop the spend projections for
7 the overall subprogram.

8 **Conservation Voltage Reduction**

9 **Q. Please explain what capital projects, activities, and other types of work will be enabled**
10 **by expenditures in the CVR subprogram.**

11 A. CVR is the capability to optimize service-point—or customer meter voltages—to reduce
12 energy demand without requiring active participation or specific investment by customers.
13 CVR uses a set of technologies, including Volt-VAR Optimization, that reduces the
14 delivery voltage along LVD circuits, thereby reducing the amount of electric load that must

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1 be served on the LVD circuit, and thus, on the electric system. The technology works
2 together and optimizes control settings on both substation and downstream voltage
3 regulating equipment. The technology allows for continuous monitoring and automatic
4 adjustment of these settings to achieve optimal voltage and load reduction while staying
5 within the regulatory requirements. CVR was part of the Company's 2018 Integrated
6 Resource Plan ("IRP") in Case No. U-20165, which was approved by the Commission in
7 2019, and the 2021 IRP in Case No. U-21090, which was approved by the Commission in
8 2022. This subprogram of the Capacity Program funds capital projects necessary for
9 implementing the Company's overall CVR plan that is included in the IRP.

10 **Q. What is included in these capital projects?**

11 A. The purpose of these projects is to install and upgrade equipment to ensure that the targeted
12 LVD circuits can enable CVR without providing voltage to customers outside the
13 allowable range. These projects include installing Distribution Supervisory Control and
14 Data Acquisition ("DSCADA"), regulator controllers, and capacitor controllers on targeted
15 circuits, as well as work to address potential voltage issues. The Company uses AMI data
16 to determine voltage levels being provided to customers; if a customer's existing voltage
17 is outside the range that would allow CVR optimization, the Company will complete circuit
18 conditioning work, including but not limited to transformer upgrades, line reconductoring,
19 as well as other solutions to improve the voltage.

20 **Q. What benefits will customers realize through the Company completing work, at the**
21 **requested spending level, in the CVR subprogram?**

22 A. The benefits of CVR were discussed in the Company's IRP filings in Case Nos. U-20165
23 and U-21090. In those filings, the Company forecasted that CVR would provide energy

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and demand savings, as well as loss reduction, as shown in Figure 58. The amount of energy savings for each project in this subprogram are identified in the Benefit Type and Benefit columns of Exhibits A-166 (JMP-1), page 37, and A-167 (JMP-2), page 28.

FIGURE 58
CVR CUMULATIVE ENERGY AND DEMAND SAVINGS

	Actual ⁹					Projected ¹⁰						
Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cumulative Peak MW Reduction	0.4	5.6	14.7	21.2	39.1	51	62	73	84	95	105	113
Cumulative MWh Reduction	82	5,643	23,882	69,045	125,746	119,379	144,102	168,971	193,976	219,160	244,450	262,399

Q. How does the Company ensure proper measurement and verification of CVR performance?

A. When the Company initially began enabling CVR on LVD circuits in 2019, the Company tested CVR performance by cycling CVR on and off on successive days and using substation DSCADA data and customer smart meter data to measure actual CVR savings by comparing data when CVR was on versus when it was off. This initial testing creates a baseline for CVR performance. Once CVR is fully enabled and operational on a circuit, the Company's DSCADA and meter data provides sufficient telemetry to ensure continuous measurement and verification of CVR performance. A third-party evaluator has also verified that the methodology and the results obtained from the Company's analysis are valid and that it is reasonable to assume similar results will be obtained from additional circuits as CVR is enabled. The full report of the third-party evaluator is provided in Exhibit A-168 (JMP-3).

⁹ Actual data from Case No. U-20165, Annual Cost Reports, Exhibit 2, columns (o) and (q), Total row.

¹⁰ Projected data from Case No. U-21090, Exhibit A-86 (MSH-1).

1 **Q. How does the Company identify CVR projects?**

2 A. CVR circuits are selected primarily based on customer types and circuits with smart grid
3 capabilities. Smart grid equipment will eventually be available on approximately 85% of
4 the LVD circuits; therefore, circuits that are not cost-effective for DSCADA deployment
5 are ruled out from CVR consideration. Additionally, circuits that contain primarily C&I
6 customers were removed. The principal reason for this is that industry analysis has shown
7 that CVR is more effective on residential load types. From within this circuit candidate
8 pool, circuits are selected based on those that had lower anticipated costs. For example,
9 circuits that have already deployed the necessary upgrades to substation and line equipment
10 were prioritized. Additionally, circuits where less capital investment would be required,
11 as determined by a power flow study, were prioritized. The power flow study process also
12 identifies the various projects needed to enable CVR for each circuit.

13 **Q. Please identify the projects that will be accomplished with the requested spending**
14 **level in the CVR subprogram.**

15 A. The Company has identified upgrades to 75 circuits for the bridge period, listed in Exhibit
16 A-166 (JMP-1), page 37, and 85 circuits for the test year, listed in Exhibit A-167 (JMP-2),
17 page 28. The Company developed the projected costs of the projects in these exhibits
18 considering estimated costs for materials and labor, and the Company's previous
19 experience performing similar projects. These exhibits also identify the location and
20 benefits of the projects.

1 **Q. What are the Company's projected bridge period and test year spending levels, for**
2 **which it is requesting cost recovery, in the CVR subprogram?**

3 A. The Company is projecting CVR capital expenditures of \$5,586,000 for the bridge period,
4 as shown in Exhibit A-113 (MPK-3), line 26, column (k), and \$4,070,000 in the test year,
5 as shown in Exhibit A-113 (MPK-3), line 26, column (l). This level of spending will enable
6 the Company to add CVR to 85 circuits in 2025 and 85 circuits in 2026.

7 **Q. How did the Company develop its projected expenditures in this subprogram?**

8 A. Spending in this subprogram is designed to implement the Company's CVR plan, as
9 originally proposed and approved in Case No. U-20165, subsequently updated, and
10 approved in Case No. U-21090. Further, the implementation plan remains consistent with
11 the plan presented in Case No. U-21389, with approximately 85 circuits planned per year
12 until the final year of deployment in 2030.

13 **Q. What has been the historical actual spending in the CVR subprogram and how does**
14 **that compare to prior cases?**

15 A. Comparisons of historical spending, projected expenditures in the case, and past approved
16 IRP projections are shown in Figure 59. The cumulative historical expenditures plus
17 projected expenditures in this case are compared to the cumulative approved IRP
18 projections in Figure 59. The Company has maintained its cumulative CVR historical
19 expenditures and rate case projected expenditures at or below the cumulative projections
20 provided in the IRP cases.

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FIGURE 59
CONSERVATION VOLTAGE REDUCTION EXPENDITURES

	Projected			Historical
	U-20165¹¹	U-21090¹²	This Case	Expenditures
2018	\$970,000			-
2019	\$1,700,000			\$81,743
2020	\$2,500,000			\$1,936,593
2021		\$4,070,930		\$7,191,370
2022		\$4,151,389		\$3,145,109
2023		\$3,964,031		\$1,311,828
2024		\$3,877,052		\$2,246,000
2025 Bridge Period		\$4,391,000 --	\$4,391,000 \$5,586,000	
2026 Test Year			-- \$4,070,000	
2020-2024 Five-Year Average	\$3,712,600			\$3,166,000
2018-2024 Total	\$21,233,000			\$15,939,643
2018-2026 Total	\$25,624,000			\$25,595,643

Q. Does an average unit cost accurately reflect the expected spending per project for this subprogram?

A. No. Average unit cost is not a good measure of spend to predict the cost of an individual project in this subprogram. There is a wide variance among work required ranging from \$5,000 to as high as \$400,000 per project.

Metering and Transformers

Q. What will the Meters and Transformers portion of your testimony discuss?

A. This section will address the Company's single purchase plans for LVD Metering and LVD Transformers. Projected spending and benefits are explained in detail in the sections below.

¹¹ Case No. U-20165, Exhibit A-67 (MAO-1), column (e).

¹² Case No. U-21090, Exhibit A-87 (MSH-2), column (f).

LVD Metering

Q. Please explain what capital projects, activities, and other types of work will be enabled by expenditures in the LVD Metering subprogram.

A. The LVD Metering subprogram supplies meters and associated equipment including meter sockets, metering transformers, and meter testing equipment. Historically, LVD Metering expenditures were allocated between the New Business and Demand Failures programs, but LVD Metering has always operated through a single purchase plan, and in this filing the Company has combined them into a single subprogram under Demand Failures. Meter Sockets and Electric Capital Meter Test Equipment costs are allocated across the total meter and metering transformer units to determine the overall cost per unit for this subprogram.

Q. How are the projected LVD Metering expenditures aligned with the Reliability Roadmap?

A. Following the Commission's March 1, 2024 Order in Case No. U-21389, the Company decided to defer replacement of 4G LTE meters to a later date. The Company's 4G LTE communications network provider has not provided a definitive date for the retirement of the 4G LTE network, but expect to maintain the network into the mid- to late- 2030s. With that in mind, the Company is evaluating its existing metering technology, vendors, and software, including technology to support future electric and gas system integrations. By year-end 2025, the Company expects to have defined an approach for eventually replacing 4G meters.

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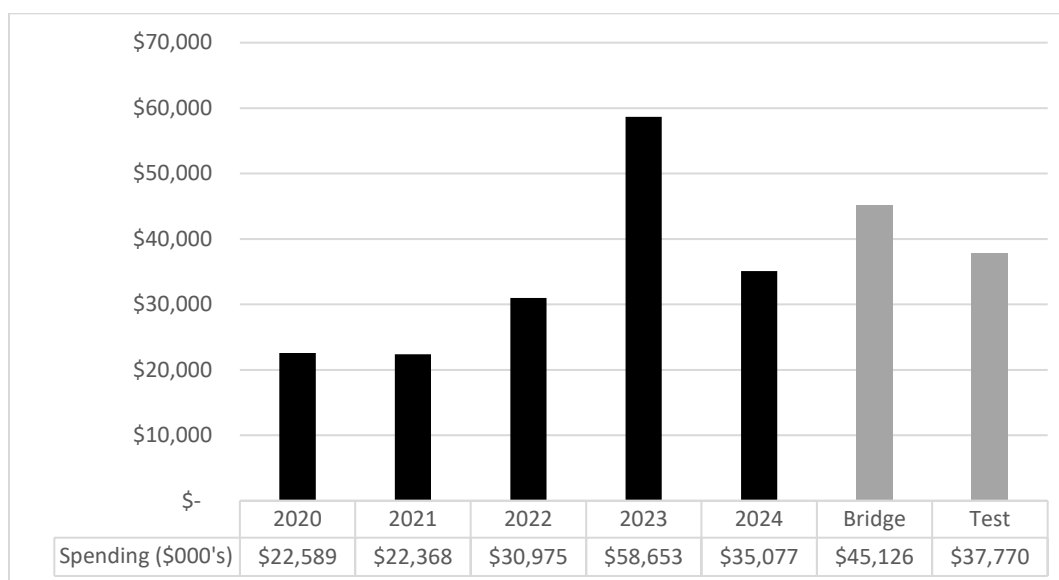
Q. What are the Company's projected bridge period and test year spending levels, for which it is requesting cost recovery, in the LVD Metering subprograms?

A. The Company is projecting unit and capital expenditures in the bridge period and test year for each of the metering subprograms as identified in Figure 60 below. The projections for LVD Metering capital expenditures are shown in Exhibit A-113 (MPK-3), line 35, columns (k) and (l). The Company's historical actual spending in the LVD Metering subprograms, along with the bridge period and test year forecasts, are shown below in Figure 61.

FIGURE 60
METERING SUBPROGRAMS EXPENDITURES AND UNITS

Subprograms	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
LVD Metering New Business	\$18,050,400	27,634	\$15,108,000	20,726
LVD Metering Demand Failures	\$27,075,600	41,451	\$22,662,000	31,088
Total	\$45,126,000	69,085	\$37,770,000	51,814

FIGURE 61
LVD METERING SUBPROGRAMS TOTAL EXPENDITURES



1 **Q. How did the Company develop its projected expenditures in the LVD Metering**
2 **subprograms?**

3 A. The expenditures in the metering subprograms are based on projected activity in the New
4 Business and Demand Failures subprograms, which is in turn based largely on historical
5 data. The Company also considers estimates of new business connections in future years
6 and forecasted large project work.

7 **Q. What benefits will customers realize through the Company completing work in the**
8 **LVD Metering subprograms?**

9 A. Metering is an essential part of the Company's broader requirement to connect new
10 customers through its overall New Business Program, as well as to replace failed
11 equipment through the overall Demand Failures Program. Additionally, advanced
12 metering is an essential component in many of the Company's present and future demand
13 response and renewable programs.

14 The New Business subprogram, in combination with the Demand Failures
15 subprogram, maintains metering accuracy by replacing meters in-service that are
16 nonfunctional, damaged, or whose accuracy has been questioned by the customer. New
17 meters are tested upon purchase to ensure meters being deployed to new business and
18 demand failure locations are compliant with accuracy requirements.

19 **Q. What are the historical unit costs for the LVD Metering subprograms?**

20 A. Historical unit costs for the LVD Metering subprograms are provided in Figure 62 below.
21 Note for 2021, 156,960 smart meters were replaced as part of the 3G to 4G-CatM1
22 changeout project; the replacement meter came with new functionality, the ability to
23 communicate with gas meters, at a cost of \$7 per meter. This increased functionality allows

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1 all the Company's smart meters to communicate with gas meters, allowing the meters to
2 be used throughout the service territory. Including these meters in the subprogram unit
3 cost calculation skewed the unit cost for 2021 to \$109. If these units are not included in
4 the unit cost calculation, the unit cost for 2021 is \$432. This skewing also occurred in
5 2022, though to a smaller extent, from \$541 to \$253 per unit.

6 The table in Figure 62 breaks out the categories of purchases included and the
7 associated unit costs for each category. There are no units for meter sockets and meter test
8 equipment as many of the costs in those categories are minor materials; the total cost of
9 meter sockets and test equipment are allocated across the total units of the other categories.
10 During the bridge period and test year, the overall unit cost is being impacted by several
11 factors. For legacy meters, the Company is purchasing higher cost units for C&I
12 applications, to accommodate those customers' complex billing and data requirements.
13 The Company had been using and recycling inventory of these units, but the vendor
14 discontinued the models that were being used. The new units are more expensive, and the
15 Company is acquiring a working inventory over the bridge period and test year. The
16 increase in metering transformer units, meter socket spending, and polyphase smart meter
17 purchases are related to conversions of 400-amp services from present configurations to
18 instrument transformer rated installations. Presently, any meter work at these locations
19 requires de-energization to do the work safely. Transitioning these to transformer rated
20 installations will increase safety for Company employees and customers.

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FIGURE 62
LVD METERING UNITS AND UNIT COSTS

	2020	2021	2022	2023	2024	Bridge	Test
Legacy Meters							
Legacy Units	564	480	101	240	420	1,387	1,040
Unit Cost	\$ 1,485	\$ 105	\$ 1,359	\$ 149	\$ 1,033	927	\$ 927
Smart Meters							
Smart Meter Units	40,863	41,339	50,125	97,784	64,749	56,864	42,648
Unit Cost	\$ 311	\$ 293	\$ 371	\$ 366	\$ 223	229	\$ 306
3G/4G Replacements							
3G/4G Units	17,520	161,284	67,440	44,760			
Unit Cost	\$ 9	\$ 20	\$ 18	\$ 208			
Metering Transformers							
Transformer Units	3,490	2,603	4,770	5,090	5,985	10,835	8,126
Unit Cost	\$ 2,026	\$ 1,842	\$ 1,759	\$ 1,743	\$ 988	\$ 748	\$ 761
Meter Sockets & Test Equipment							
Spending (000's)	1,821	2,244	2,642	3,763	2,974	5,213	3,910
Allocated Unit Cost Impact	\$ 29	\$ 11	\$ 22	\$ 25	\$ 42	\$ 75	\$ 75
Total Subprogram							
Total Units	62,437	205,706	122,436	148,874	71,154	69,085	51,814
Total Unit Cost	\$ 362	\$ 109	\$ 253	\$ 390	\$ 493	\$ 653	\$ 729

Q. Please explain the variation in total costs and in unit costs over time.

A. Total expenditures for LVD Metering have varied from year to year based on the mix in quantity and type of meters, metering transformers, and meter sockets the Company has had to purchase. During 2021, 2022, and 2023, the Company experienced increased meter failures due to contaminated meter batteries. This failure primarily occurred in meters that were outside of the manufacturer warranty period of three years. To replace the failed meters, the Company purchased additional meter quantities in 2022 and 2023 to meet the demand for failure replacements, and to complete 3G meter conversions. The unit cost for meters includes dollars allocated for meters, metering transformers, and meter sockets. The

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overall variation in the unit cost of meters is also related to variation in the mix both in quantity and type of devices, as shown in Figure 63.

FIGURE 63
LVD METERING UNITS



The average unit costs in the metering transformer category were consistent from 2019 through 2023. For 2024, the unit costs were lower due to the mix of transformers purchased, with an increase in the number of smaller, less expensive current transformers. In 2021 and 2023, legacy meter unit costs were lower due to the quantity and mix of meters purchased. In 2021 and 2023 the only legacy meters purchased were 2S 200 Amp residential meters. For the other years, including the forecast for the bridge period and test year, there are higher quantities of polyphase meters included that are read via the

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1 Company's MV90 system. They are categorized as Legacy meters as they were not part
2 of the Smart Energy Deployment project. These meters are installed on large C&I electric
3 customer locations. Smart meter unit costs were lower in 2021 due to lower numbers of
4 polyphase meters purchased, then increased in 2022 and 2023 due to the purchase of more
5 polyphase meters. Smart meter pricing is contractually fixed until 2032.

6 **Q. Why is the Company continuing to purchase any legacy meters after the end of the**
7 **implementation of smart meters?**

8 A. The legacy meters in the Company's purchase plan primarily support operation of MV90
9 meters. MV90 meters essentially provide a type of automated meter reading for
10 approximately 5,000 large C&I customers, by which meter interval data is collected either
11 by an internet-over-IP or telephone communication with the meter. MV90 meters were
12 determined to be out of scope for initial smart meter deployment for two main reasons.
13 First, the billing tariffs for these customers are complex and would have required extensive
14 hours of programming; since MV90 was already functional, the Company kept these
15 meters out of scope for initial smart meter deployment. Second, some of these MV90
16 meters have a pulse output to provide real time data to customers and at the time of smart
17 meter implementation through the present time, the meter vendor did not offer a smart
18 meter option with pulse output, so the use of MV90 legacy meters was still required.
19 Legacy meters, in very small numbers, are also purchased to support metering installations
20 for customers who opt-out of the smart meter program.

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1 **Q. Does an average unit cost accurately reflect the expected spending per project for this**
2 **subprogram?**

3 A. No. Average unit cost is not a good measure of spending per project for this subprogram.
4 There is a wide variance among different meter types ranging from \$125 per meter to as
5 high as \$6,000 per meter. There is also a wide variance among metering transformers and
6 meter sockets. Metering transformers range from \$60 per unit to \$2,500 per unit and meter
7 sockets range from \$26 per unit to \$911 per unit. When projecting annual spend in this
8 subprogram, the Company does use historical usage across meter types over the last three
9 years, as shown in Figure 64, as the basis for future purchase plan quantities. In addition,
10 the plan considers major known projects that will require metering and associated devices
11 in establishing the purchasing plan by device type. This establishes the meter mix and
12 subsequent unit price submitted in the rate case. As the actual year progresses, the mix of
13 meters will change based on the actual work mix requiring meters and associated devices
14 that will impact the unit prices from year to year.

15 **LVD Transformers**

16 **Q. Please explain what capital projects, activities, and other types of work will be enabled**
17 **by expenditures in the LVD Transformers subprogram.**

18 A. The LVD Transformers subprogram supplies the distribution transformers that provide the
19 means to supply electricity to customers at an acceptable voltage, with the number of
20 transformers needed driven primarily by activity in the LVD Lines New Business
21 subprogram. Historically, LVD transformers purchases have been allocated across the
22 New Business, Demand Failures, and Capacity programs for accounting reasons, but
23 because these separate LVD transformers subprograms operated through a single purchase

1 plan for distribution transformers, the Company is combining all LVD transformer
2 purchases into a single subprogram under New Business for rate case purposes.

3 **Q. How are the projected LVD Transformers expenditures aligned with the Reliability**
4 **Roadmap?**

5 A. As noted in the Reliability Roadmap, supply chain issues have led to an increase in the unit
6 costs of transformers, and while the Company is working to diversify its supply chain, it
7 must continue to purchase transformers to meet customer demand, and in fact must increase
8 purchase levels to catch up from shortages experienced during the COVID-19 pandemic.

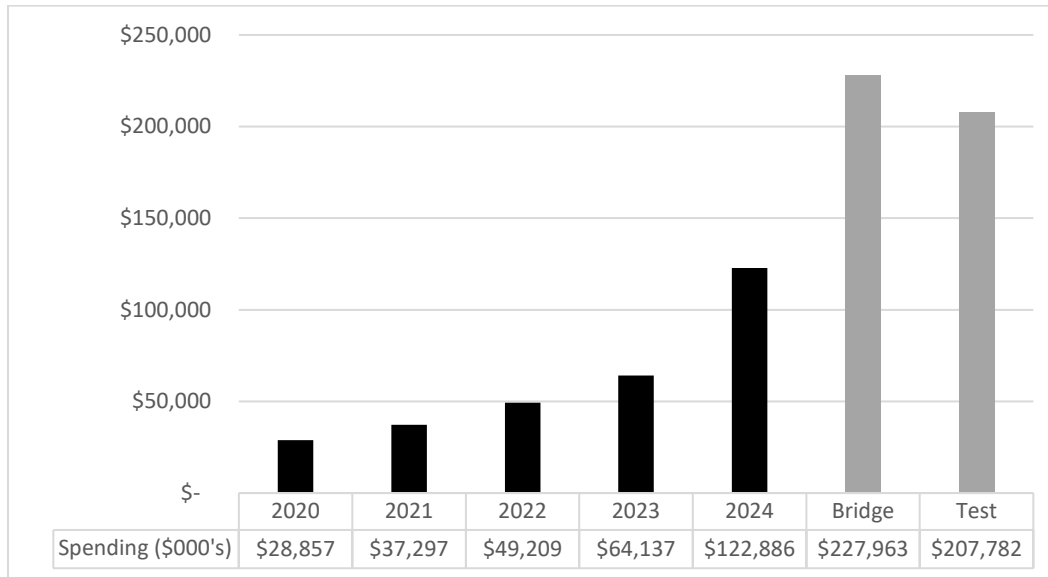
9 **Q. What benefits will customers realize through the Company completing work, at the**
10 **requested spending level, in the LVD Transformers subprograms?**

11 A. The installation of distribution transformers is an essential part of the Company's broader
12 requirement to connect new customers through its overall New Business Program, the
13 benefits of which were described earlier in my direct testimony. The benefits of specialized
14 transformers like voltage regulators allow the Company to condition the voltage on
15 distribution circuits to ensure service to customers is delivered within the voltage range
16 specified in Company tariffs.

17 **Q. What are the Company's projected bridge period and test year spending levels, for**
18 **which it is requesting cost recovery, in the LVD transformers subprograms?**

19 A. The Company is projecting LVD Transformers capital expenditures of \$227,963,000 in the
20 bridge period, as shown in Exhibit A-113 (MPK-3), line 5, column (k), and \$207,782,000
21 in the test year, as shown in Exhibit A-113 (MPK-3), line 5, column (l). The Company's
22 historical actual spending in the LVD Transformers subprograms, along with the bridge
23 period and test year forecasts, are shown below in Figure 64.

FIGURE 64
LVD TRANSFORMERS SUBPROGRAMS TOTAL EXPENDITURES



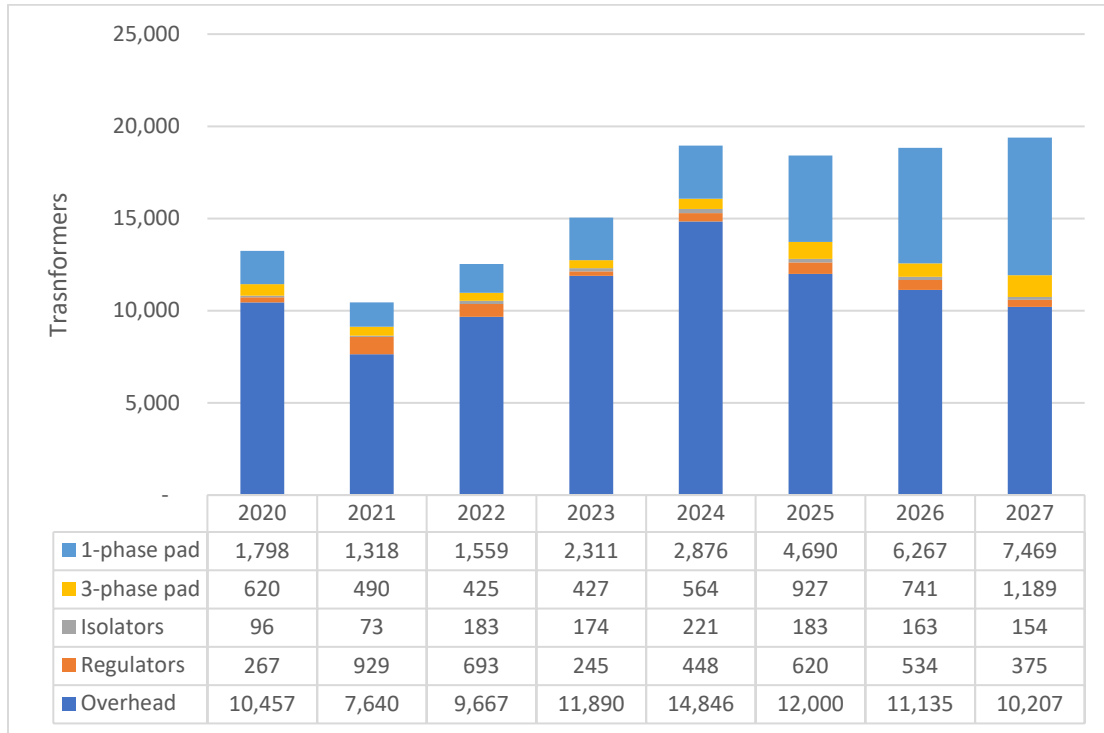
1 **Q. How did the Company develop its projected expenditures in the LVD Transformer**
2 **subprograms?**

3 A. The Company develops its distribution transformer purchase plan by estimating the total
4 number of transformers needed, based on historical actual data, with potential fluctuation
5 in individual years based on lines projects in the Company's reactive spending programs.
6 The historical number of transformer purchases (for 2020 through 2024) is shown in
7 Figure 65 below, followed by projected purchases in future years (for 2025 through 2027).
8 In 2025 and beyond, the Company expects that purchases of overhead transformers will
9 remain generally level, but the Company is planning for a continued significant increase in
10 purchases of padmount transformers tied to increased undergrounding work for both new
11 service connections and primary and secondary circuits; for general new business work;
12 and for the need to support customers adopting EVs as described in the Reliability
13 Roadmap. Furthermore, in 2022, the supply market for transformers in the United States

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dropped significantly due to shortages in labor and raw materials, and the Company continues to invest in higher levels for purposes of ensuring it has restocked its inventory.

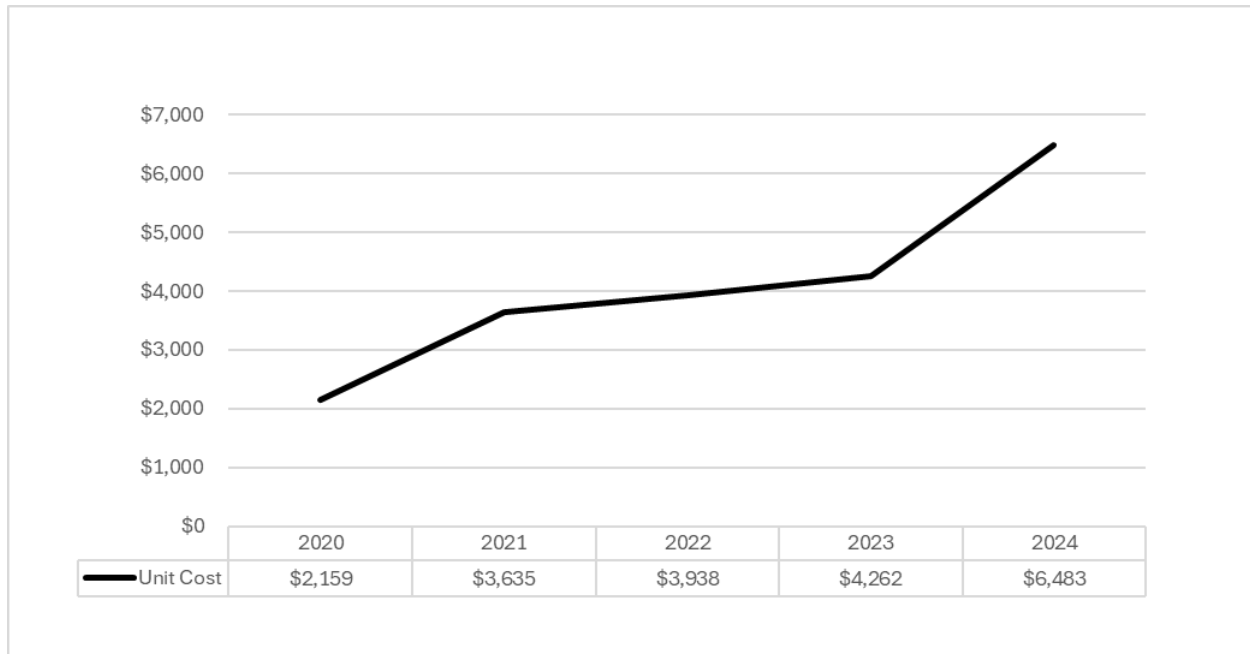
FIGURE 65
LVD TRANSFORMERS UNITS



Q. What are the historical unit costs for the LVD transformers subprogram?

A. The historical unit cost of transformers is provided in Figure 66.

FIGURE 66
LVD TRANSFORMERS UNIT COSTS



1 **Q. Please explain any variation in unit costs over time.**

2 A. Unit costs for transformers have increased over the historical period, partially due to
3 inflation. The transformer sector, as an industry, has experienced at least a 6% increase
4 year-over-year in cost, and this increase is projected to continue at 5% in the future.
5 Additionally, the Company maintains an inventory of more than 400 transformer types,
6 and unit costs each year can vary depending on the mix of transformer types the Company
7 purchases each year. For example, in 2020 the Company received less of the more
8 expensive units like regulators. This, coupled with increased volume of units at a lower
9 cost, led to a lower average cost per unit in 2020. For 2021 and 2022, raw material
10 shortages and labor issues caused domestic supply to shrink and the cost of transformers
11 in each year to increase by 30% over the previous five-year historical averages as noted in
12 this testimony. In total, the cost of padmount transformers increased by 50% from 2022
13 and 2024 due to demand/supply imbalances.

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1 As a result of these supply challenges, the Company initiated a supply base diversification
2 strategy, including new overseas manufacturers. This supply base diversification was
3 necessary to mitigate lead-time increases and capacity risks with domestic manufacturers.
4 Transportation and higher manufacturing costs from these suppliers led to higher unit costs
5 in 2024 (transportation costs are higher for products that must be shipped from other
6 countries). In addition, demand for lower-priced units like overhead transformers has
7 slowed while demand for larger three-phase and single-phase transformers has increased
8 in this same period. In short, the Company's supply diversification strategy for
9 transformers has better ensured that the Company can meet customer demand, but did
10 involve increased costs.

11 **Q. Does an average unit cost accurately reflect the expected spend per transformer for**
12 **this subprogram?**

13 A. Unit cost is not an ideal measure of spending to predict the cost of a single transformer in
14 this subprogram, as it includes a wide range of transformer types which are not directly
15 comparable. Transformers can cost as little as \$500 but also as much as \$15,000 or more
16 depending on application. The transformer purchase plan includes traditional transformers
17 that serve the purpose to provide service to customers as well as specialized transformers
18 like voltage regulators that respond to changes in voltage on the primary system and adjust
19 to ensure adequate voltage. As noted above, demand for larger, higher cost single-phase
20 and three-phase transformers has increased while overhead units have leveled off.

Electric Other Program

Q. What is included in the Electric Other Program?

A. Company witness Kelly introduces the Electric Other Program in his direct testimony. This testimony will address the Tools sub-program. The Electric Other Program also includes the Computers and Equipment; System Control Projects; and Grid Technologies sub-program, which are addressed by Company witness Hayward in her direct testimony.

Tools

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the Tools sub-program.

A. This sub-program covers the purchase of new and replacement tools for utility workers that are worn, broken, outdated, and/or unrepairable when the tools are priced over \$1,000 per item. Some examples of these tools covered in this sub-program include:

- Cordless cutting, crimping, and hammering/breaking tools
- Concrete cutting/boring tools with silica mitigation systems
- Remote cutting and spiking tools
- Calibrated metering tools
- Customer service integrity meters
- Sub-Station Testing instruments
- System/service diagnostic or locating equipment
- Line segmenting (load drop/load pickup) devices
- System reconductoring accessories
- Specialty rigging, work lighting, pumping or “bridging” and “matting” equipment

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1 Since 2016, this sub-program included outfitting new Company trucks, including
2 service bucket trucks, two-person buckets, and digger derricks with standard packages of
3 essential tools to ensure that crews go into the field with appropriate equipment, referred
4 to as “truck tool kits.” The funds for these truck tool kits are transferred from the Tools
5 sub-group to Fleet, allowing for the purchase of the truck tool kits to coordinate with the
6 purchase/delivery of each new truck. The purchase plan for these truck tool kits is based
7 on the Company’s fleet acquisition and deployment plan. As the Company is planning to
8 expand its Operations workforce, the Company will need to purchase additional capital
9 tools (besides truck tool kits).

10 **Q. What benefits will customers realize through the Company completing work, at the**
11 **requested spending level, in the Tools sub-program?**

12 **A.** A properly outfitted truck and crew enable a safer, faster response to outages, safe and
13 efficient installation of new services, and more productive completion of projects with less
14 waste and lower unit costs. Company crews require appropriate tools and equipment when
15 in the field, both to ensure their own safety and the safety of the public, and to be able to
16 complete their work in an expeditious manner to complete maintenance and construction
17 work and reduce outage times. Spending in this sub-program ensures that tools are
18 replaced in a timely manner before the expiration of the tool’s life, while ensuring that
19 Company trucks are always stocked with appropriate tools for workers to safely complete
20 their work.

1 **Q. What are the Company's projected bridge period and test year spending levels, for**
2 **which it is requesting cost recovery, in the Tools sub-program?**

3 A. The Company is projecting capital expenditures of \$10,001,000 in the bridge period, as
4 shown in Exhibit A-113 (MPK-3), line 43, column (k), and \$8,248,000 in the projected test
5 year, as shown in Exhibit A-113 (MPK-3), line 43, column (l).

6 **Q. What is the basis for the Company's projected spending level in this sub-program?**

7 A. The projected spending level in this sub-program is based on the needs of the Company for
8 capital tools and truck tool kits. The cost of capital tools is based on prices quoted from
9 vendors for the specific models. Prices for each tool make and model can vary annually
10 due to inflation and other supply chain constraints.

11 The tool purchases in the bridge period will support all electric operations,
12 including the new Underground Construction group that focuses on installing new
13 customer underground infrastructure, including primary cable and transformers. Figure 67
14 outlines the Company's bridge period investment categories and units in the Tools
15 sub-program.

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FIGURE 67
BRIDGE PERIOD INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Capital
Truck Tool Kits (93 units)	\$3,362,000
Other Capital Tool Purchases	
<i>General Capital Tools</i>	<i>\$3,039,000</i>
<i>Reconducting Trailer Equipment</i>	<i>\$100,000</i>
<i>Employee Fall Restraint</i>	<i>\$250,000</i>
<i>Klein Bin Storage System</i>	<i>\$600,000</i>
<i>Substation bird mitigation equipment</i>	<i>\$90,000</i>
<i>UG Primary Wire Stripper</i>	<i>\$700,000</i>
<i>Digger Truck 3-Phase Holder</i>	<i>\$250,000</i>
<i>Meter Service CT Lifters (ergonomics)</i>	<i>\$150,000</i>
<i>Thumpers</i>	<i>\$100,000</i>
<i>Magnetic Drills for Ductile Iron Poles</i>	<i>\$100,000</i>
<i>Light Weight Service Savers</i>	<i>\$600,000</i>
<i>Underground Department tools</i>	<i>\$660,000</i>
Total	\$10,001,000

1 In the test year, the Company will continue with its process of purchasing truck tool
2 kits for new Company trucks, with 62 truck tool kits in the test year, aligned with the
3 Company's fleet acquisition and deployment plan, necessary to support the Company's
4 expanding workforce to complete the increased workload necessary to address new
5 business requests, system capacity, and system reliability work. The increase in the Capital
6 Tool Purchases category reflects the increased need to support additional work and work
7 groups focused on the HVD system reliability. Due to the nature of this work, the tools
8 purchased for any new or additional group have a specific purpose and voltage rating, thus
9 making the investment more focused on the work practices. The Company is projecting
10 unit and capital expenditures in the test year for each investment category as identified in
11 Figure 68 below.

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FIGURE 68
TEST YEAR TOOLS INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Capital
<i>Truck Tool Kits (62 units)</i>	\$2,015,000
<i>Other Capital Tool Purchases</i>	
<i>General Capital Tools</i>	\$3,069,000
<i>Klein Bin Storage System</i>	\$600,000
<i>Reconductoring Trailer Equipment</i>	\$180,000
<i>Substation bird mitigation equipment</i>	\$100,000
<i>Battery Concrete Saw</i>	\$300,000
<i>Underground Work Group Tool Support</i>	\$457,000
<i>Fall Restraint</i>	\$250,000
<i>Hydraulic Tool Replacements</i>	\$1,277,000
Total	\$8,248,000

1 **Q. Please explain the coordination between Fleet and Electric Operations to procure**
2 **Truck Tool Kits.**

3 A. Starting in 2016, the Electric Operations Tools sub-program has set aside budgeted dollars
4 to purchase truck tool kits for the bucket and digger trucks that Fleet plans to purchase.
5 The Tools sub-program then transfers the allocated dollars to Fleet, creating a packaged
6 purchase with Fleet's selected vendor. This is done because the tools included in these tool
7 packages are considered standard equipment for the vehicles and ensure that crews go into
8 the field with the necessary resources. In 2022, however, no money was transferred for the
9 purpose of new truck tool kits. Due to Fleet-related disallowances in the Commission's
10 Order in Case No. U-20963, the Company wrote off or sold a number of vehicles. Truck
11 tool kits can only be accounted for in Fleet if there are associated vehicles; the result of this
12 was that no transfers were made in 2022.

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Historical data in Figure 69 below shows the overall annual truck tool kit dollars that were earmarked by the Electric Operations Tool department, then transferred to Fleet within the truck purchase.

FIGURE 69
TRUCK TOOL PACKAGES BY YEAR

	2020	2021	2022	2023	2024	Bridge Period	Test Year
Number of truck tool packages	47	18	0	16	24	93	62
Truck tool package spending	\$2,736,000	\$5,885,000	\$0	\$560,000	\$727,000	\$3,362,000	\$2,015,000

Q. What has been the historical actual spending in the Tools sub-program for the past five calendar years?

A. The historical actual spending in the Tools sub-program for the past five calendar years is shown in Figure 70 below. This level of spending is what the Company requires to replace capital tools in lifecycle, create consistency (for training and in-field use) between Electric Operations work groups, provide Fall Restraint tools for Apprentices and new hire Journey-workers based on the total of individuals hired, and support the purchase of truck tool packages to equip the Company's growing workforce.

FIGURE 70
TOOLS HISTORIC EXPENDITURES

2020	2021	2022	2023	2024	5-Year Average
\$3,611,000	\$5,214,000	\$5,257,000	\$4,560,000	\$7,773,000	\$5,283,000

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1 **Q. Please explain year-over-year variation in spending in this sub-program.**

2 A. Spending in this sub-program has been increasing for three reasons. First, the Company
3 has been purchasing truck tool packages for LVD line worker vehicles since 2016, and in
4 2021 began purchasing them for other groups in the Electric Operations department as well.
5 Second, tool prices have increased, and the Company has invested in newer types of tools
6 to improve safety. As more tools reach the end of their useful life and must be replaced,
7 the Company's spending in this sub-program has increased to replace older tools with safer
8 and more advanced ones. In particular, the Company has invested in more ergonomic tools,
9 such as battery-operated cutters, drills, impact wrenches, and crimpers, to reduce the
10 frequency and severity of injuries and achieve occupational health goals. Third, the
11 Company has created a new workgroup to support Underground construction. This
12 workgroup has driven an increase in truck tool kit purchases and purchases of tools used
13 in underground utility work.

14 **SUMMARY**

15 **Q. Please provide a brief summary of your testimony and the intent of investing in LVD**
16 **capital subprograms to support the Company's electric distribution system.**

17 A. The testimony provided an overview of the LVD system and associated capital investments
18 to improve reliability and resiliency of the system while serving new customers to support
19 economic development in the state of Michigan. The testimony provided detail of each
20 LVD capital investment program and the basis of planned investments and benefits. The
21 LVD capital investments outlined in my testimony are identified and planned to support
22 the overall objectives and strategy outlined in the Company's Reliability Roadmap and
23 those introduced by Company witness Kelly.

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1 **Q. Please summarize the LVD capital expenditure plan in this filing.**

2 A. The LVD capital expenditure plan outlined in this testimony is summarized in Figure 71
3 below. Dollars shown are in thousands.

FIGURE 71
LVD CAPITAL EXPENDITURE SUMMARY (\$000)

	2024 Actuals	Bridge Period	Test Year
LVD Capital	\$632,197	\$1,055,533	\$1,086,679

4 **Q. Does this complete your direct testimony?**

5 A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

DANIEL A. SCHMOEKEL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

DANIEL A. SCHMOEKEL
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1 **Q. Please state your name and business address.**

2 A. My name is Daniel A. Schmoekel, and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am employed as Senior Strategy Manager for Electric Distribution for Consumers Energy
6 Company (“Consumers Energy” or the “Company”). In that capacity, I am responsible for
7 developing prioritized plans in alignment of Company goals for improvement of electric
8 assets, safety, and compliance.

9 **Q. What is your educational background?**

10 A. I graduated from Michigan Technological University with a Bachelor of Science Degree
11 in Civil Engineering in 2006. In addition, I graduated from Grand Valley State University
12 in 2018 with a Master of Business Administration degree. I earned a Professional
13 Engineering license (State of Michigan) in 2011, and achieved certification as a Project
14 Management Professional (Project Management Institute) in 2013.

15 **Q. Please describe your business experience.**

16 A. Following graduation from Michigan Technological University, I worked as an engineer
17 at OHM Advisors (Livonia, Michigan) until 2008. In 2008, I joined Consumers Energy as
18 a project engineer responsible for capital improvement projects at the B.C. Cobb
19 Generating Facility (“Cobb”), a now-retired, five-unit power plant located in Muskegon,
20 Michigan. In 2010, I accepted a position as a Mechanical Maintenance Supervisor at Cobb,
21 where I was responsible for establishing the work schedule and prioritizing work
22 assignments for mechanical maintenance personnel, as well as ensuring policies and
23 practices of the Working Agreement were followed. In 2011, I accepted a position as a

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1 System Owner at the J.H. Campbell Complex (“Campbell”) in West Olive, Michigan, a
2 three-unit coal-fired generating facility. As a System Owner, my responsibilities included
3 providing engineering and technical direction to identify and correct operational, design,
4 and maintenance related issues. I was then promoted to Production Engineer at Campbell
5 Unit 3, where I monitored plant operating parameters and identified/investigated
6 equipment deficiencies. In 2015, I was promoted to Production Lead at Campbell Unit 3.
7 In this position, I ensured interim acceptance of all Campbell Unit 3 Air Quality Control
8 Systems related equipment per applicable Consumers Energy policies and procedures,
9 performed technical reviews of system operating procedures/new equipment modification
10 designs, and managed the Operating and Maintenance and capital budgets for the Campbell
11 Unit 3 Operations Department. In 2018, I transferred to the Operations, Finance, and
12 Planning organization as the Electric Dispatch Principal Team Lead. In this role, I had
13 operational responsibility for Low Voltage Distribution dispatching and management of
14 the planning and scheduling functions of short cycle streetlight work orders for 30
15 Headquarters across Consumers Energy’s electric service territory. In October 2021,
16 I accepted the role of Manager of Streetlight Programs. In this role I oversaw billing
17 reconciliations, asset management, and contracts, and managed budgets for street lighting
18 programs. In March 2023, I was promoted to Asset Strategy Manager (and then promoted
19 to Senior Strategy Manager in July 2023). In this role, I develop prioritized plans in
20 alignment with Company goals for improvement of electric assets, and safety and
21 compliance.

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1 **Q. Have you previously provided testimony before the Michigan Public Service**
2 **Commission (“MPSC” or the “Commission”)?**

3 A. Yes, I provided testimony in the Company’s 2022, 2023, and 2024 Electric Rate Case Nos.
4 U-21224, U-21389, and U-21585, respectively.

5 **Q. What is the purpose of your direct testimony in this proceeding?**

6 A. The purpose of my direct testimony is to support the Streetlight Program requests in this
7 case. Toward that end I will:

- 8 • Describe Consumers Energy’s streetlighting assets and provide an overview of
9 the Company’s strategic plan for management of those assets. Aspects of the
10 strategic plan include streetlighting outage restoration performance,
11 accelerated/planned conversions, streetlighting resources, planned
12 maintenance, and customer outage reporting;
- 13 • Support the reasonableness and prudence of the capital expenditures for the
14 conversion of overhead-fed cobrahead streetlights for the historical year ended
15 December 31, 2024, the 16-month bridge period beginning January 1, 2025,
16 and ending April 30, 2026, and the projected test year beginning May 1, 2026,
17 and ending April 30, 2027;
- 18 • Support the reasonableness and prudence of the capital expenditures for the
19 conversion of high intensity discharge (“HID”) overhead-fed cobrahead
20 streetlights that are located in the vicinity of failed overhead-fed cobrahead
21 fixtures for the historical year ended December 31, 2024, the 16-month bridge
22 period beginning January 1, 2025, and ending April 30, 2026, and the projected
23 test year beginning May 1, 2026, and ending April 30, 2027;
- 24 • Support the reasonableness and prudence of the capital expenditures for the
25 installation of new customer-requested streetlighting assets for the historical
26 test year ended December 31, 2024, the 16-month bridge period beginning
27 January 1, 2025, and ending April 30, 2026, and the projected test year
28 beginning May 1, 2026, and ending April 30, 2027; and
- 29 • Discuss the Company’s streetlight outage restoration performance.

30 **Q. How are the following sections of your direct testimony organized?**

31 A. My direct testimony is divided into the following sections.

32 I. Consumers Energy Company-owned Streetlight Assets

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II. Consumers Energy Plan for Streetlights

III. Streetlight Outage Reporting and Restoration

IV. LED Streetlight Equivalency Evaluations and New Business

V. Conversion of Cobrahead, Post Top, and Center Suspension Streetlights

VI. Planned Streetlight Conversions

Q. How is your direct testimony related to the direct testimony of other Company witnesses?

A. Company witness Michael P. Kelly sponsors the operations and maintenance (“O&M”) expense associated with operating the streetlighting program, whereas I will be supporting the capital expenditures associated with operating the streetlighting program.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-12 (DAS-1)	Schedule B-5.9	Summary of Actual and Projected Electric Capital Expenditures for the Years 2020 through 2027.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

**I. CONSUMERS ENERGY COMPANY-OWNED
STREETLIGHT ASSETS**

Q. Please provide an overview of the Company’s streetlight assets.

A. The Company owns and maintains approximately 173,000 streetlights. The majority of these streetlights are cobrahead fixtures (see Figure 1 below). In addition to the 119,000 cobrahead fixtures, the Company has approximately 11,000 center suspension streetlights and approximately 43,000 post-top fixtures, which make up the total quantity of 173,000 streetlights.

FIGURE 1
COBRAHEAD FIXTURE WITH LIGHT EMITTING DIODE



1 The streetlights the Company owns primarily fall in one of two buckets: HID and light
2 emitting diode (“LED”).

3 HID luminaires include mercury vapor (“MV”), high pressure sodium (“HPS”), and
4 metal halide (“MH”). The MV, MH, and LED streetlights typically have a similar color
5 temperature (white light) whereas the HPS streetlights typically have an amber color.

6 **Q. Is the HID technology obsolete?**

7 A. Not entirely. Pursuant to the Energy Policy Act of 2005,¹ the MV technology has been
8 discontinued and is obsolete. As I will discuss later in this testimony, the Company has
9 taken a planned conversion approach to replacing the MV technology. Manufacturers are
10 discontinuing HID offerings and the Company is replacing HPS technology for cobrahead,
11 post top, and center suspension fixtures. The continuously evolving LED technology is far
12 more energy efficient than any of the available HID technologies.

¹ PL 109-58; 119 Stat 631. See Section 135.

1 **II. CONSUMERS ENERGY’S PLAN FOR STREETLIGHTS**

2 **Q. Please provide an update on the Company’s continuing efforts to improve its**
3 **streetlighting service.**

4 A. As I will discuss later in this direct testimony, the Company has engaged additional
5 resources, implemented its Streetlight Outage and Restoration (“SOAR”) application,
6 completed a streetlight patrol and fix initiative, completed an initiative for advanced
7 lighting controls, and developed a modified conversion plan for its HID cobrahead and post
8 top fixtures—all to support improved outage restoration performance.

9 **Q. How has the Company collaborated with its stakeholders in arriving at some of the**
10 **program improvements?**

11 A. The Company has continuously supported interaction with its customers, including the
12 Michigan Municipal Association for Utility Issues (“MI-MAUI”), in developing its
13 streetlighting improvements. The Company met with MI-MAUI seven times in 2024 to
14 discuss streetlighting reliability reporting, and operational progress to identify
15 opportunities for improvement and enhance customer experiences. Throughout the
16 collaborative process, the Company has been receptive to suggestions for process
17 improvements.

18 **Q. Does the Company plan to continue its collaboration with its stakeholders to identify**
19 **future program improvements?**

20 A. Yes. Consistent with the Commission’s suggestion in Case No. U-20963 to continue to
21 collaborate with MI-MAUI and other parties to address streetlighting concerns, the
22 Company and MI-MAUI continue to meet bi-monthly to discuss relevant street lighting
23 topics.

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1 **Q. Was streetlighting reliability a topic in the MPSC electric distribution audit in Case**
2 **No. U-21305?**

3 A. No. Streetlighting reliability was not a topic in Case No. U-21305

4 **Q. Does the Company have a long-term plan documented for improving the reliability**
5 **of its streetlights?**

6 A. Yes. The ideal state for the Company's streetlight program is to repair or replace
7 streetlights only at the end of the component lifecycle, rather than having to replace
8 components that fail early. Extending the lifecycle of the luminaire reduces repair
9 expenses across the Company's streetlight portfolio. The Company has documented its
10 streetlight reliability plan in the Reliability Roadmap. Please see Exhibit A-129 (MPK-19),
11 for the Company's latest version of the Reliability Roadmap.

12 **III. STREETLIGHT OUTAGE REPORTING AND RESTORATION**

13 **Q. What actions has the Company taken to improve streetlight outage performance?**

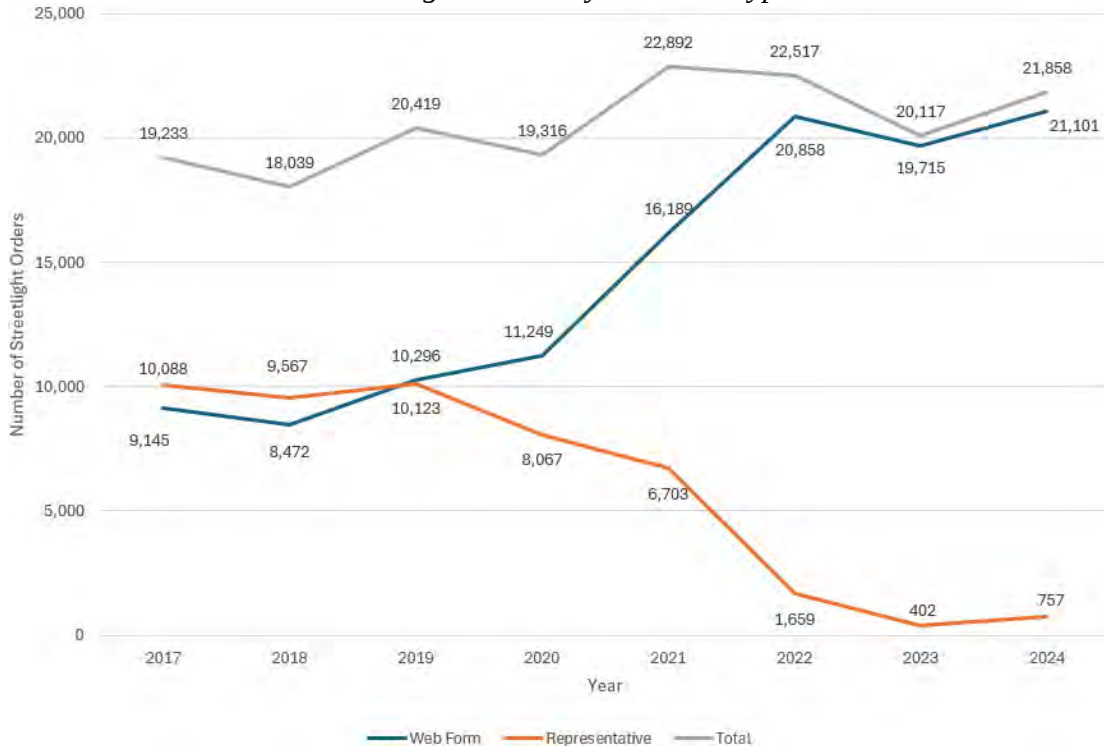
14 A. In 2022, the Company initiated a proactive plan to convert HID cobrahead streetlights
15 located in the vicinity of failed cobrahead streetlights to LED because every proactive
16 conversion eliminates a future HID streetlight outage. In 2024, 478 HID cobrahead
17 streetlights were proactively converted. To date, 3,049 HID cobrahead streetlights have
18 been proactively converted to LED. The Company completed the patrol and fix initiative,
19 and advanced lighting controls initiatives in 2022 (discussed later in this direct testimony).
20 Additionally, the Company is evaluating different contracting strategies to improve outage
21 duration.

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Q. Please describe the Company's 2024 streetlight outage restoration performance.

A. A total of 21,858 streetlight incidents were reported in 2024, 97% of which were reported via the SOAR application. Historical streetlight order creation by type is shown in Figure 2 below where the SOAR Application (Web Form) constitutes 21,101 of the incidents.

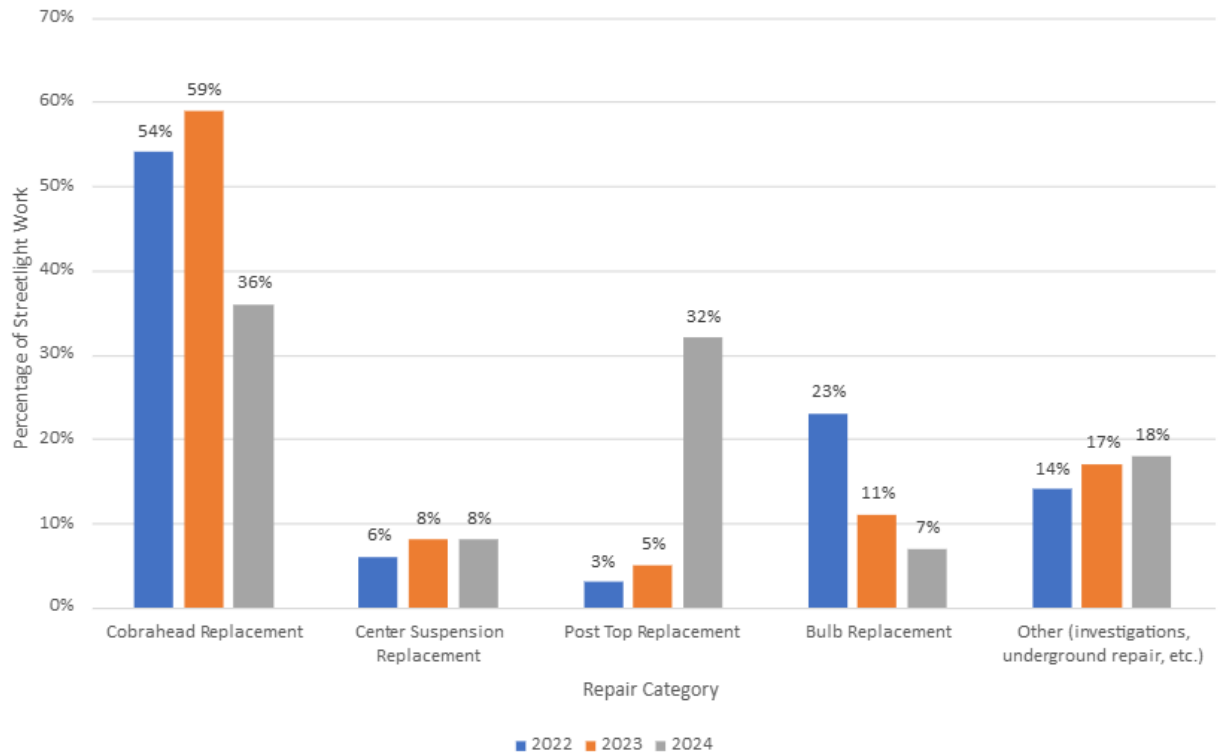
Figure 2
Streetlight Orders by Creation Type



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These incidents between 2022 and 2024 resulted in the work as shown in Figure 3 below.

Figure 3
Work Type Breakdown of 2022 through 2024 Streetlight Orders



In 2024, the average streetlight outage duration was 14.65 days and the median outage duration was 7 days. In 2024, the average outage and median outage duration degraded compared to 2023 by 4.92 days and 2 days, respectively. Activities to improve streetlight outage performance are discussed later in this direct testimony.

Q. Does the Company prioritize other work ahead of streetlight outage restoration?

A. The Company prioritizes public safety related orders and emergent service restoration ahead of streetlight outage repairs. The workers who complete streetlight repairs are the same workers who perform emergent service restoration and respond to downed wire orders. While the Company has a financial incentive to prioritize streetlight repairs

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1 because it is required to compensate streetlight customers with a streetlight outage credit
2 pursuant to its tariff, it must prioritize restoration work in order of public impact.

3 **Q. What does the Company believe are the causes or contributing factors of the increase**
4 **in the number of streetlight orders from 2017 to 2024?**

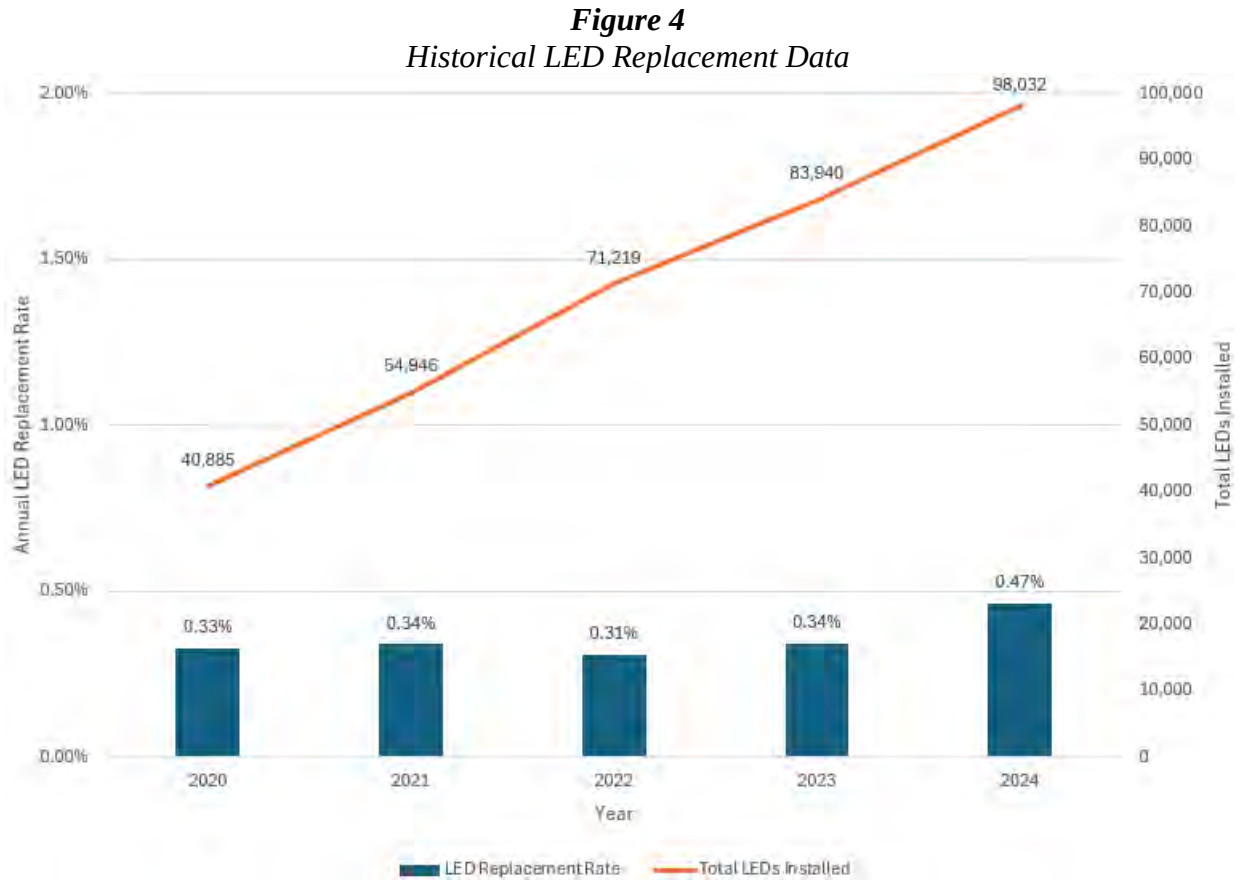
5 A. The Company believes the increased number of orders reflected in Figure 2 above reflects
6 greater reporting of outages due to implementation of the SOAR application—not that the
7 Company is necessarily experiencing more outages – because customers now have an easy-
8 to-use self-service application for reporting streetlight outages. Additionally, the Company
9 is no longer performing any lamp maintenance/replacement as it is converting HID
10 cobrahead and post top fixtures upon failure. This practice is expected to result in a
11 relatively uniform conversion of cobrahead and post top fixtures across nearly all
12 municipalities and will ultimately lead to reduced streetlight orders due to the reduced
13 maintenance required for LED streetlights.

14 **Q. What are the causes or contributing factors for the 27% increase in post top**
15 **replacement orders in 2024?**

16 A. The increase in post top replacement orders in 2024 is a result of LED conversion upon
17 first failure mode of post top fixtures. Historically, if an HPS bulb was burnt out, the bulb
18 would be replaced, not the entire fixture. This would result in a “Bulb Replacement”
19 category order.

1 **Q. What is the historical LED replacement rate?**

2 A. Historical LED replacement data is shown below in Figure 4. LEDs are very reliable
3 with a less than 0.5% replacement rate.



4 **Q. Can the Company determine whether the LED luminaires it installs are defective**
5 **without tracking outages by luminaire type?**

6 A. Yes, the Company can determine whether LED luminaires are defective without tracking
7 outages by luminaire type.

8 For product changes, the Company uses the First Part Approval process to validate
9 the material changeover from HID to LED fixtures. This ensures the product meets
10 standards and specifications.

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For LED lighting defects (product non-conformances) identified by the field, the field team notifies the Supplier Quality Department; the Supplier Quality Department documents the quality issue and determines whether it is a non-conformance, the Company notifies the supplier of the defect, and the Company determines corrective actions. Street lighting non-conformances are documented in the Company's quality management software to record corrective and preventative actions required to prevent recurrence. Supplier Quality implemented tracking of product non-conformances in the Company's quality management software in 2022.

Q. Were there any streetlighting product non-conformances that required the removal and replacement of field installed equipment in 2024?

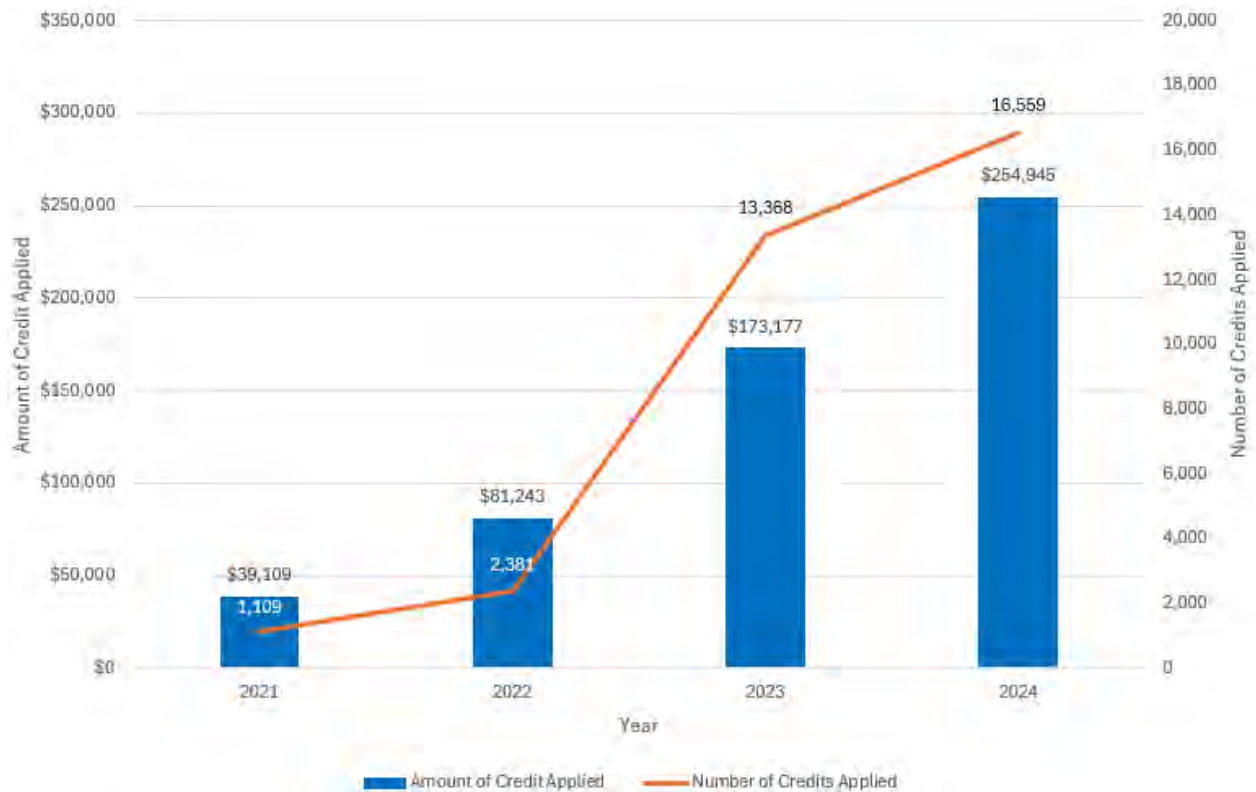
A. No. There were no streetlighting product non-conformances that resulted in the removal and replacement of field installed equipment in 2024.

Q. Does the Company provide credits to customers for streetlight outages?

A. Yes. Pursuant to the Company's current streetlight tariffs, the Company provides a pro-rated bill credit calculated from the date a streetlight outage is reported and continuing until the light is returned to service. The streetlight outage credit is issued within 90-days of the streetlight returning to service.

The Company provides an outage credit for each and every streetlight outage. However, the number of outage credits applied does not always equal the number of actual outages; outage credits by customer may reflect multiple outages for the same type of light. For example, if a customer has five 40-watt streetlight outages within a billing period, one credit would be applied for the total amount of the credits for all five lights. Historical streetlight outage credit data is shown in Figure 5 below.

Figure 5
Historical Streetlight Outage Credit Data



The increase in the number of outage credits applied between 2022 and 2024 is a direct result of the methodology for application of outage credits for all streetlight outages, regardless of duration (MPSC Case No. U-21203).

Q. Are there circumstances in which longer duration outages are unavoidable?

A. Yes. In certain circumstances, the ability to safely and timely restore a streetlight can be difficult. Streetlight knockdowns, underground cable faults, requirements for traffic control, and replacement of special-order materials can sometimes lead to longer duration streetlight outages.

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1 **Q. Does the Company monitor longer duration outages and their status?**

2 A. Yes. All streetlight outages greater than 60 days are discussed in weekly workplan
3 meetings. The Company's target is no more than 125 streetlight outages statewide
4 exceeding 60 days in duration.

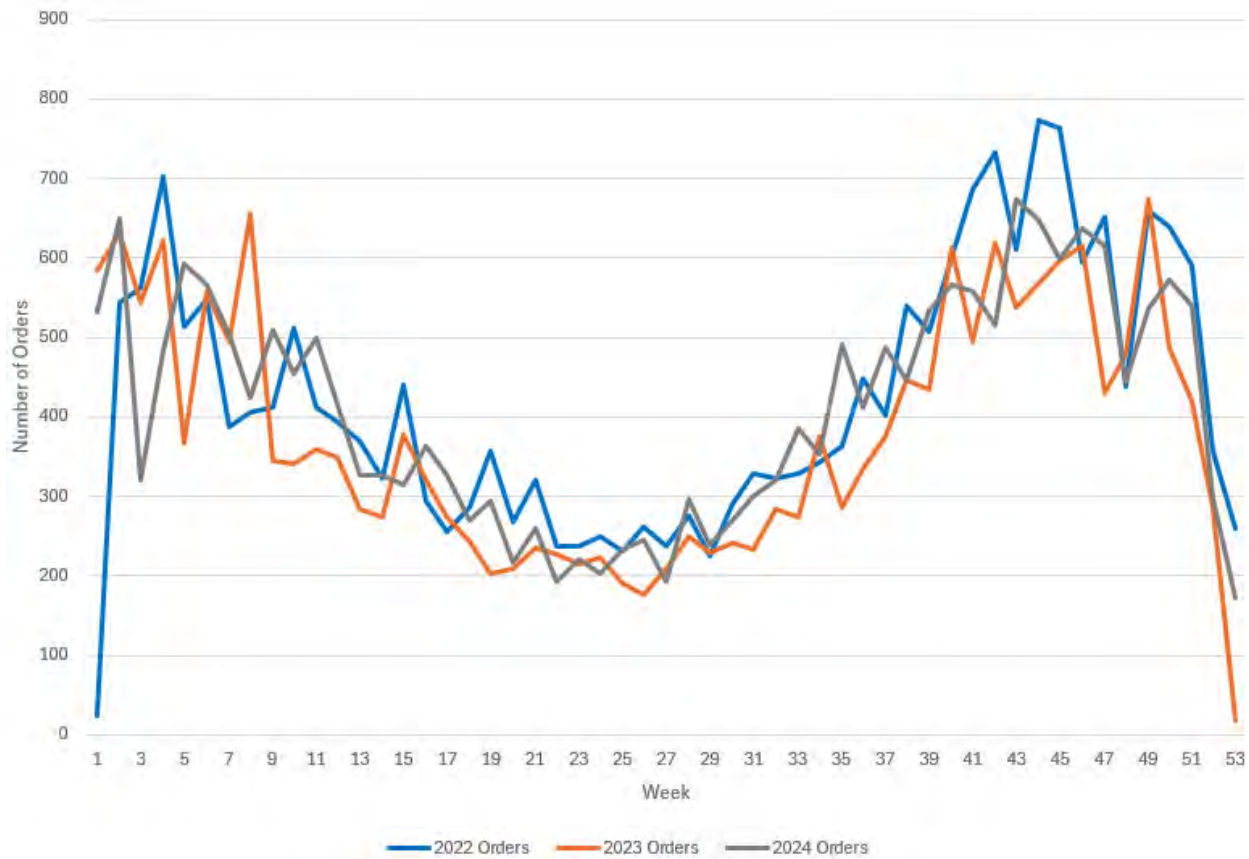
5 **Q. Are longer duration outages localized, or do they occur through Consumers Energy's**
6 **service territory?**

7 A. Longer duration outages generally occur throughout Consumers Energy's service territory
8 proportionate to the geographic dispersion of streetlights.

9 **Q. Has the Company made any decisions regarding the future performance of streetlight**
10 **outage restoration work?**

11 A. Yes. Based upon variability of outages reported throughout 2022, 2023, and 2024, the
12 Company has determined it will continue to employ a blend of Company resources and
13 contractors to complete streetlight outage restoration work and vicinity upgrades. This
14 resource strategy will allow the Company to flex its contracted resources to meet changing
15 streetlight outage restoration demand. Figure 6 below represents differing levels of outages
16 reported throughout the year, driving the need for a blended workforce.

Figure 6
Weekly Streetlight Order Count



1 **Q. What other actions has the Company taken to improve streetlight outage restoration**
2 **performance?**

3 A. In addition to the implementation of cobrahead and post top vicinity upgrades, the
4 Company completed a patrol and fix initiative (November 2021 through March 2022),
5 completed an advanced lighting controls initiative in October 2022, solicited feedback
6 from internal and external stakeholders regarding its SOAR application, completed one
7 SOAR application upgrade, and is underway with the second SOAR application upgrade,
8 completed evaluation of advanced lighting control implementation, and documented its
9 long-term reliability plan in the Company's Reliability Roadmap. The Company has also
10 implemented internal prioritization standards for restoration of outages greater than

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60 days. With the exception of cobrahead and post top vicinity upgrades, the Company is not seeking to recover any investment in these initiatives.

Q. What were the results of the patrol and fix initiative?

A. The patrol and fix initiative was in place between November 2021 and April 2022 in the Adrian and Kalamazoo service territories, and in place mid-February 2022 through March 2022 in the Muskegon service territory. In total, nine cobrahead fixtures in Adrian, one cobrahead fixture in Kalamazoo, and six cobrahead fixtures in Muskegon were identified as failed and repaired upon identification.

Q. Does the Company intend on reinstating its patrol and fix initiative during the bridge period or test year?

A. Not at this time. From January 1, 2022 through March 31, 2022, 1,499 streetlight outages were reported by customers in the Adrian, Kalamazoo, and Muskegon service territories. Time spent searching for 16 outages that weren't reported is time that could have been spent repairing identified outages. The quantity of outages reported by customers is indicative of their adoption of the Company's reporting technology and its effectiveness relative to the patrol and fix initiative.

Q. What were the results of the advanced lighting controls initiative?

A. 204 total smart nodes were installed statewide (Flint, Jackson, Leelanau, Kalamazoo, Muskegon, and Marshall Training Center). The data collection period was October 1, 2022, through October 31, 2022. Ten smart nodes of each manufacturer were installed at each location (except Marshall Training Center). Evaluation criteria included: status of light visibility, identification of fault information, accurate metering of power usage, and energy savings provided for the customer.

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Capabilities observed: manually turning streetlights on/off, manual dimming of streetlights, creation of scheduled dimming events, outage reporting of streetlights, and status communication of streetlights.

Q. Does the Company intend on reinstating the advanced lighting controls initiative in the bridge period or projected test year?

A. Not at this time. The Company completed an internal review of the initiative to determine the viability of technology implementation. The Company also surveyed participating municipalities in the first quarter of 2023 to collect feedback regarding features they like to use, software package preference, and overall customer sentiment for installation of advanced lighting controls. A formal business case will be prepared, and a summary of the results will be submitted for approval in a future electric rate case prior to any implementation. The 204 smart nodes remain in-service, and the Company continues to partner with the initiative participants to identify use cases and to define functional requirements for broader installation.

Advanced lighting controls provide features and functions that some municipalities may find beneficial, while some municipalities may find the expense outweighs these benefits. The Company will continue to gauge interest from its street lighting customers and evaluate project feasibility through established business planning processes.

Q. What were the results of the Company's internal review of the advanced lighting controls initiative?

A. Feedback from municipalities included not using all the product functionality, concern over internal cost to maintain, and concern over cost of implementation. Estimated O&M savings (reduced truck rolls) were less than anticipated costs associated with maintaining

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1 the devices in the field and managing the digital experience (manage software program,
2 integration with existing software (SAP, SOAR, etc.), coordination with manufacturer and
3 municipalities, and maintenance of the new rate and tariff).

4 The Company has decided to pause implementation of advanced lighting controls
5 based on the cost of the technology, lack of customer interest, and minimal O&M savings.

6 **Q. Does the Company recommend other activities which are expected to improve outage**
7 **restoration performance and/or reduce streetlight failures?**

8 A. Yes. The Company's current practice of proactively converting HID cobrahead lights, via
9 vicinity conversion, to LED luminaires has proven financially beneficial to street lighting
10 customers. Approximately \$291,000 in customer savings has been realized since 2022
11 through vicinity conversions by reducing non-premise time of field personnel. The
12 Company will continue to perform cobrahead vicinity conversions as part of its expected
13 work plan. As discussed further in this direct testimony, the Company recommends
14 continuing HID to LED post top conversions upon failure and implementing vicinity
15 conversion of HID post top lights. In 2024, 6,018 post top lights were converted to LED
16 technology, extending the life of these assets.

17 **Q. When did the Company begin converting HID post top streetlights to LED?**

18 A. The Company began converting HID post top streetlights to LED in January 2024.

19 **Q. Why does the Company convert HID post top streetlights to LED?**

20 A. Post top streetlights represent the second largest quantity of HID streetlights the Company
21 operates and maintains (approximately 43,000). Post top streetlights are typically unique,
22 meaning other manufacturers do not produce the same exact streetlight. The Company's

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1 HPS luminaire suppliers have indicated HPS post top streetlights have been discontinued
2 mainly due to low demand amidst a higher demand for LED luminaires.

3 Implementing a post top reactive conversion program, similar to that already in
4 place for cobrahead luminaires, would result in similar customer benefits (reduced energy
5 use, no upfront cost, etc.). This work plan is documented in the Company's Reliability
6 Roadmap.

7 **Q. Why does the Company recommend implementing vicinity conversions for HID post**
8 **top streetlights?**

9 A. Customer feedback received during HID cobrahead conversions indicate customers are
10 sensitive to variation in lighting temperature (color). This sentiment is expected to be
11 amplified in post top lighting applications, where lights are typically installed for
12 beautification and the light temperature variation may not be aesthetically appealing.
13 Vicinity conversion of HID post top lights reduces appearance of lighting temperature
14 differences, leading to sustained or increased customer satisfaction, and improved
15 reliability. Preliminary analysis of HID post top streetlight vicinity conversions indicates
16 savings and improved reliability of service for street lighting customers.

17 **Q. How did the Company evaluate vicinity conversions for HID post top streetlights?**

18 A. The Company analyzed savings from 2022 when completing vicinity conversions on
19 cobrahead streetlights. Vicinity conversions reduce the unit cost per conversion by
20 reducing frequency of repair worker mobilization to the same area. Table 6 below
21 illustrates the difference between a reactive conversion and a vicinity conversion.

22 The Company's latest version of the Reliability Roadmap (Exhibit A-129
23 (MPK-19)) reflects an assumption of 4,713 HID post top to LED conversions per year (800

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vicinity conversions) starting in 2025. This equates to customer savings of \$92,000 per year versus exclusively reactive conversion.

Q. What is SOAR and what is it intended to provide?

A. SOAR is a web-based application that allows customers to self-report streetlight outages. SOAR was implemented to increase customer satisfaction through self-service capabilities, reduce information technology related costs, reduce incoming call volume for contact centers, and improve the process for handling streetlight outages.

Q. When did the Company begin using the SOAR application.

A. The Company launched the SOAR application in 2021.

Q. Please describe the benefits of the SOAR application.

A. The SOAR application benefits customers in a variety of ways. Specifically, the SOAR application project deployed an accurate self-service streetlight outage notification program for use by customers, providing accurate streetlight outage identification and more rapid restoration resolution. Additionally, the project defined appropriate repair manifests and global positioning system (“GPS”) locations to ensure deployed repair crews have the correct equipment and location. The project also provided customers with the capability to immediately identify the status of the repair online and avoid the need to contact Customer Service. Figure 7 below demonstrates streetlight information for a user-selected streetlight with the option to report an outage in SOAR. Figure 8 below shows in-service, in-progress, and extended repair streetlights on the SOAR map. Figure 9 below shows the status of the repair. Blue lights are operational, orange lights are reported as outages.

Figure 7
SOAR Screenshot: Streetlight Information

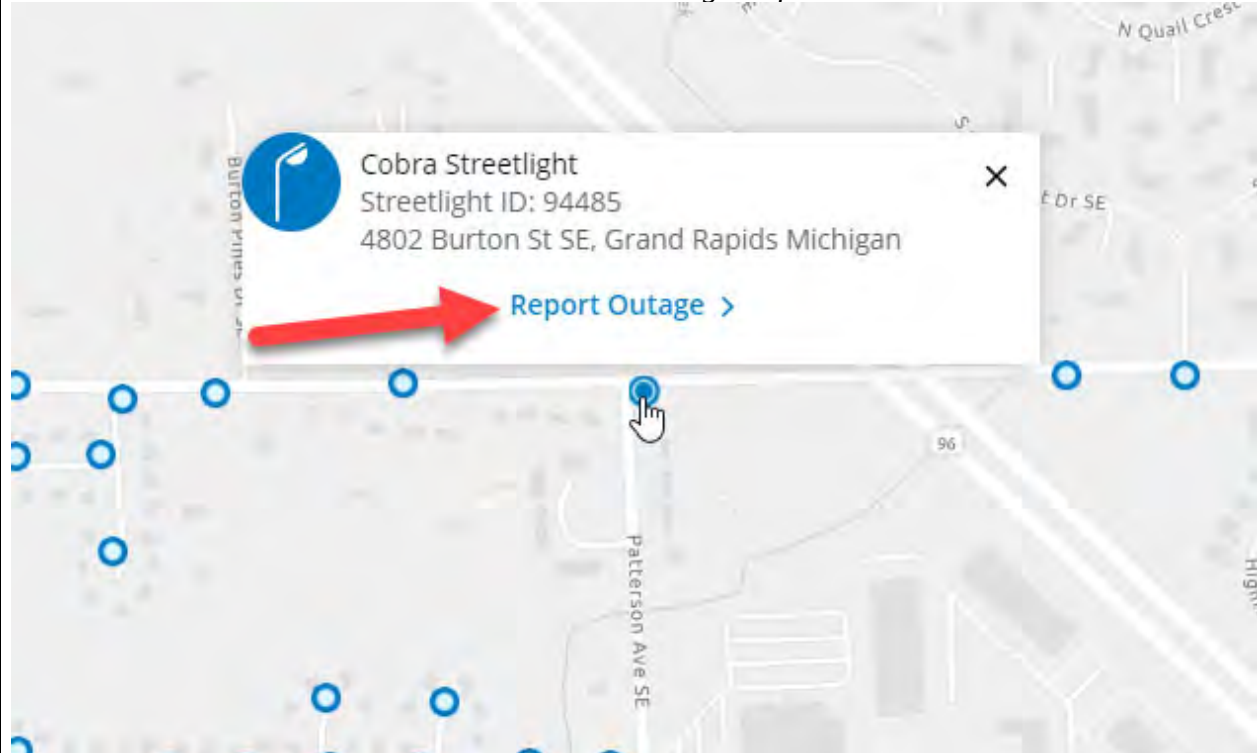


Figure 8
SOAR Screenshot: Streetlight Status on SOAR Map

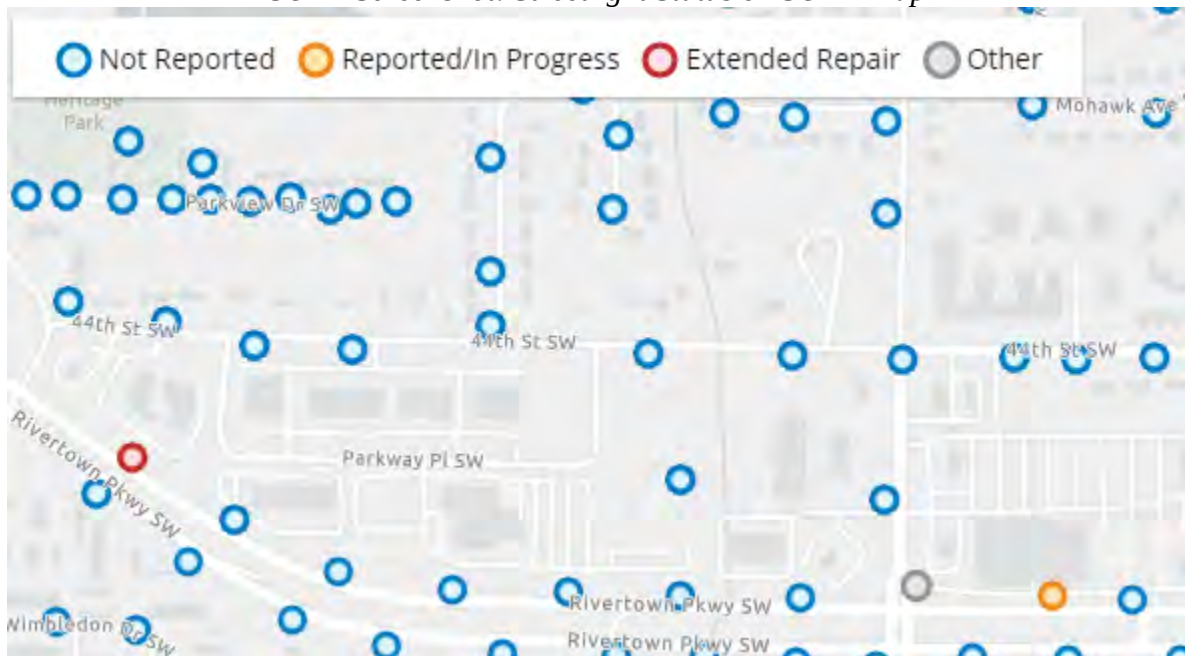
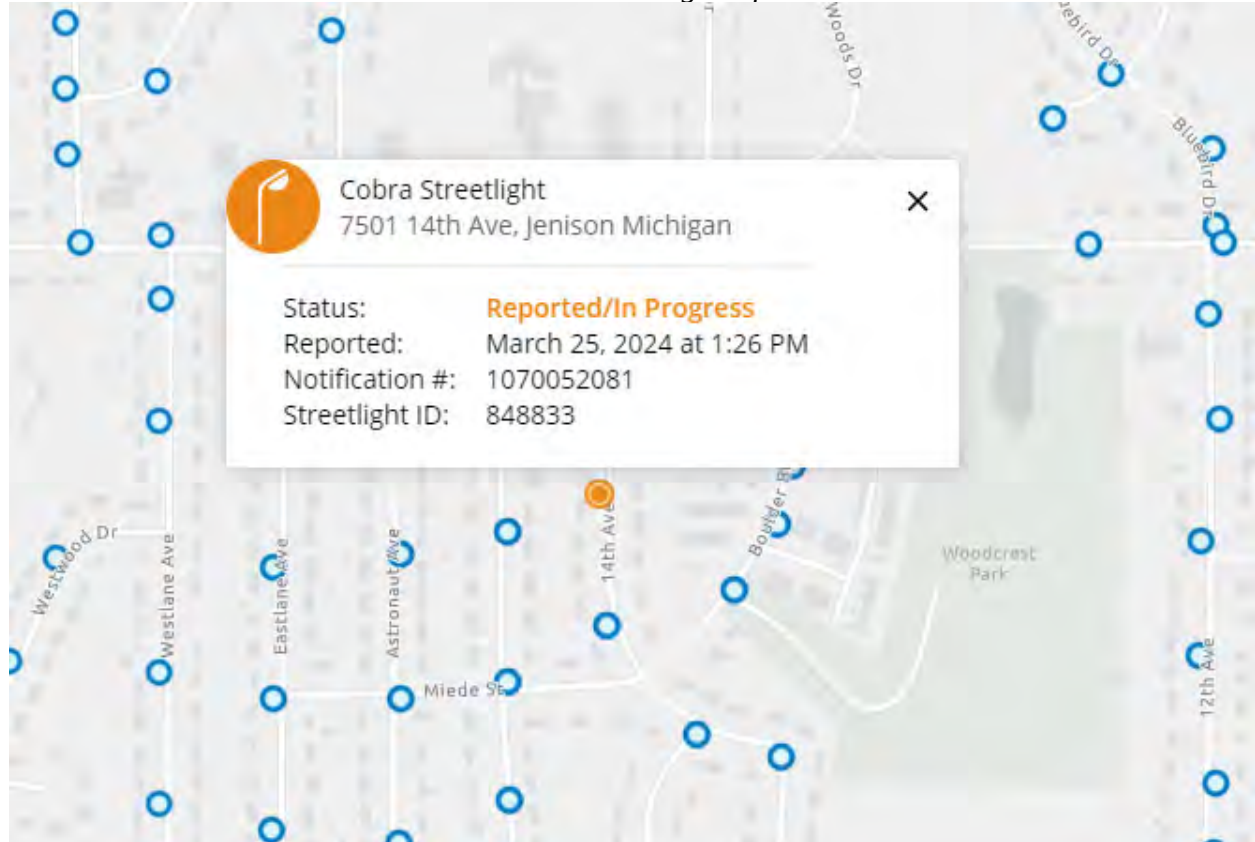


Figure 9
SOAR Screenshot: Outage Repair Status



1 **Q. Does the SOAR application provide economic benefits in addition to the qualitative**
2 **benefits previously described?**

3 A. Yes. The SOAR application provides cost reductions in several ways. First, the SOAR
4 application is projected to reduce customer calls, resulting in annual savings of \$38,500
5 and resulting in improved customer satisfaction. Second, the SOAR application will
6 eliminate duplicate reported outages, resulting in projected annual savings of \$1.5 million
7 due to the elimination of duplicate truck rolls (nearly 14% of the 20,419 streetlights
8 reported in 2019 were duplicate orders). In addition to the projected cost reductions for
9 the call center and field services, the SOAR application is projected to reduce annual
10 Information Technology (“IT”) support costs by \$60,000 as a result of consolidating
11 streetlight portal components into the core customer facing portal.

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1 **Q. Where are these economic benefits accounted?**

2 A. The economic benefits have already been incorporated into the unit cost of the work the
3 Company expects to conduct.

4 **Q. Has the Company created a standard reliability report for streetlighting**
5 **performance?**

6 A. Pursuant to Case No. U-21389, the Company, MI-MAUI, and MPSC staff worked together
7 to identify metrics to include in reliability reporting. The Company presented its plan to
8 MPSC staff regarding including self-service reliability reporting from the SOAR
9 application on June 5, 2024. The self-service reporting was included in Case No. U-21585.

10 **Q. Do you have any final thoughts regarding the Company's outage identification and**
11 **restoration process?**

12 A. Yes. As I have already discussed, the Company has evaluated and continues to evaluate a
13 number of different customer streetlighting service concerns, and will use continuous
14 improvement methods to identify and implement process improvements where applicable.
15 The Company has completed its patrol and fix, and advanced lighting control initiatives.
16 The Company is now converting HID post top and cobrahead fixtures to LED technology
17 upon failure. Streetlighting reliability is further advanced through the execution of vicinity
18 conversions for both cobrahead and post top luminaires. Additionally, the Company has
19 augmented its own field resources with contracted resources, and is continuing to engage
20 customers regarding advanced lighting control installations. The Company will continue
21 to collaborate with its streetlight customers, MI-MAUI, and other interested stakeholders
22 in the future, as demonstrated by its participation in the working group resulting from

1 DTE's order in Case No.: U-21534 to continue to improve the streetlighting service that it
2 provides to its customers.

3 **IV. LED STREETLIGHT EQUIVALENCY EVALUATIONS**
4 **AND NEW BUSINESS**

5 **Q. Please describe the Company's process to evaluate the equivalency of replacement**
6 **LED lighting.**

7 A. The Company relies on technical standards to help ensure the proper amount of
8 illumination is provided to roadways. The Company's primary focus in selecting
9 replacement LED lighting is the actual equivalency of the selected alternative to ensure
10 roadways are properly illuminated for safety while controlling costs. There are multiple
11 technical factors the Company evaluates to ensure equivalency, such as total light loss
12 factor, which includes lamp lumen depreciation and dirt depreciation, and roadway and
13 pedestrian activity classifications. Considerations such as the specific location of the
14 existing lighting relative to the roadway it is intended to illuminate are also important.
15 I will discuss additional standards the Company considers in its equivalency evaluations
16 later in this testimony.

17 **Q. What is the origin of the Company's equivalency standards?**

18 A. In 2014 and 2015, the Company worked closely with a lighting consultant to not only
19 develop its LED specification, but also developed a method by which the Company could
20 verify the LEDs submitted for consideration are equivalent to the luminaires they are
21 intended to replace. The method the Company uses ensures the selected LED luminaire
22 will adequately provide equivalent roadway illumination.

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1 **Q. Please specify what roadway lighting standard(s), if any, the Company follows?**

2 A. The Company uses ANSI/IUES RP-8-22 Recommended Practice for Lighting Roadway
3 and Parking Facilities.

4 **Q. Please explain what luminaire performance factors the Company evaluates for**
5 **equivalency. Please address specifically, but not exclusively, lumens, light distribution**
6 **patterns, Backlight-Uplight-Glare ratings, Correlated Color Temperature, and Color**
7 **Rendering Index.**

8 A. For equivalency, the Company uses Agi32 software to verify optimized span lengths based
9 on roadway classification and pedestrian activity to determine equivalency compared to
10 the span lengths of existing HPS cobrahead fixtures. The performance factors listed in the
11 question are used to determine conformance to the Company's specifications but not
12 equivalency.

13 **Q. How often does the Company competitively evaluate replacement lighting?**

14 A. The Company typically issues competitive solicitations every three years, with the
15 Company's most recent competitive solicitation completed in January 2025. As part of the
16 most recent solicitation, the Company evaluated the latest equivalent LEDs submitted by
17 multiple manufacturers. Streetlight technology, like many other technologies, changes and
18 improves frequently. However, it would be unreasonable to evaluate the changing
19 technology more frequently than every three years.

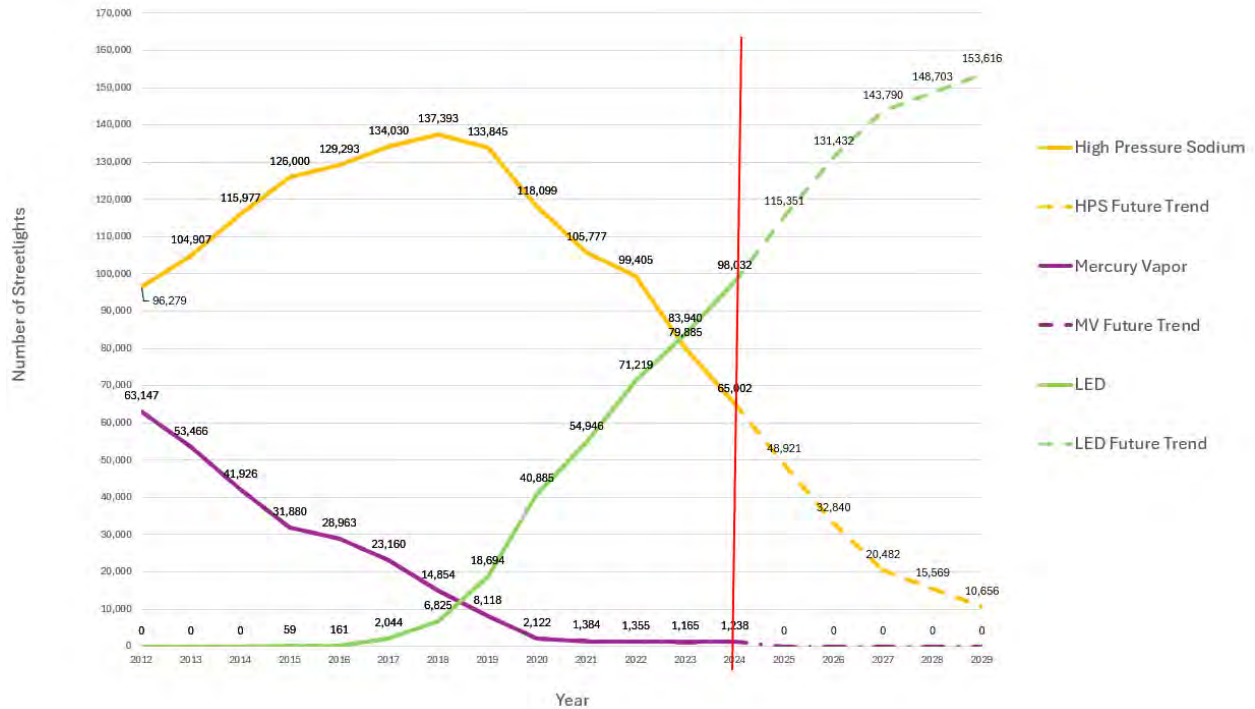
20 **Q. How have technology trends impacted installations?**

21 A. See Figure 10 below for historical and projected lighting technology installed. LED and
22 HPS Future Trends in Figure 10 (below) reflect post top LED conversions (reactive and

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vicinity), as outlined in the Reliability Roadmap (Exhibit A-129 (MPK-19), pages 127 through 132).

Figure 10
Streetlight Technology Trend



Q. For each HID cobrahead, post-top, or center suspension wattage and type (HPS, MV, MH) of which the Company had more than 3,000 deployed at the end of 2023, please provide the standard (or most common) LED equivalent wattage used before and after the 2025 competitive solicitation.

A. Pre- and post-2025 competitive solicitation LED equivalent wattages are shown in Table 1 below.

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Table 1
LED Equivalent Wattages

Fixture Type	LED Wattage Prior to 2025 Bid	LED Wattage post 2025 Bid
Cobra	40W	30W
Cobra	70W	60W
Cobra	80W	70W
Cobra	150W	140W
Center Suspension	40W	40W
Center Suspension	70W	70W
Traditional Non-Cutoff Post Top	50W	50W

1 **Q. Why doesn't the Company competitively solicit replacement lighting more**
2 **frequently?**

3 A. The effort to replace its existing LED lighting portfolio is not a small undertaking.
4 Considerations such as depletion of existing inventory, satisfaction of existing lighting
5 contracts, and complete evaluation of alternative lighting products is a considerable effort.
6 The establishment of lighting contracts that have a minimum term of three years results in
7 better unit pricing from manufacturers in comparison to contracts for only one or two years,
8 which would have smaller contract values. It would be unreasonably expensive to engage
9 in a competitive solicitation process annually. This would effectively result in the need for
10 additional resources, both engineering and supply chain, with little or no economic benefit.
11 Although manufacturers continuously improve their lighting products, the Company must
12 make strategic decisions as to how frequently it can transition from its current lighting
13 products to new lighting products.

14 **Q. How does the Company evaluate alternative LED lighting products to ensure**
15 **equivalency?**

16 A. The Company begins its evaluation of alternative LED lighting products by ensuring the
17 wattage of the replacement LED luminaire is equal to or less than the wattage of the

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1 luminaire it will replace, to ensure the replacement product's monthly rate is the same or
2 less expensive than the existing luminaire, all else being equal. The next step in the
3 equivalency process is to consider the specific roadway application, including roadway
4 classification, pedestrian activity, pavement class, roadway width, location, and mounting
5 height to ensure the average luminance, average and maximum uniformity, and the
6 maximum veiling luminance (disability glare) is in accordance with industry guidelines.
7 The next consideration for the evaluation is to perform a financial analysis among
8 replacement equivalent products for impacts to the customer as well as the Company. The
9 final consideration for the evaluation of equivalent lighting products is the aesthetics of the
10 replacement luminaire.

11 **Q. Does the Company's equivalency evaluation process ensure that replacement LED**
12 **lighting meets DesignLights Consortium ("DLC") Qualified Products List criteria?**

13 A. Yes. This criteria was included in the Company's most recent competitive solicitation for
14 LED lighting products. In addition, all LED cobrahead luminaires previously selected in
15 the Company's competitive solicitations since 2018 also met this criteria.

16 **Q. Please explain why DLC certification is important.**

17 A. DLC is a group that certifies light output used in energy rebates around the world. This
18 group independently certifies the quality and performance of lights. DLC essentially
19 ensures luminaires meet their advertised specifications for lumen output, color rendering
20 index, color temperature, total harmonic distortion, power factor, etc. Selection of a
21 DLC-certified light helps ensure you receive a quality product.

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1 **Q. Does the Company only utilize the equivalency evaluation process to support lighting**
2 **conversions?**

3 A. No. The Company also leverages the technical characteristics of the newly selected
4 lighting to support lighting designs for new streetlight installations. The Company receives
5 customer requests for installation of new streetlighting (i.e., new subdivisions) and
6 leverages the results of the LED lighting evaluations to design the new lighting.

7 The capital expenditures associated with new streetlighting are reflected in Exhibit
8 A-12 (DAS-1), Schedule B-5.9, page 1, line 1.

9 **Q. Does the Company utilize the LED fixtures for purposes other than existing light**
10 **conversion?**

11 A. Yes. The Company uses the LED cobrahead and post top fixtures in new business
12 applications as well. Projected new business expenditures are summarized in Table 2
13 below.

Table 2
Projected New Business Expenditures

Period / Year	Amount	Units
Bridge Period (ending 4/30/2026)	\$4.869 million	294
Test Year (ending 4/30/2027)	\$3.727 million	220

14 **Q. How did the Company develop the projected capital expenditures for streetlighting**
15 **new business?**

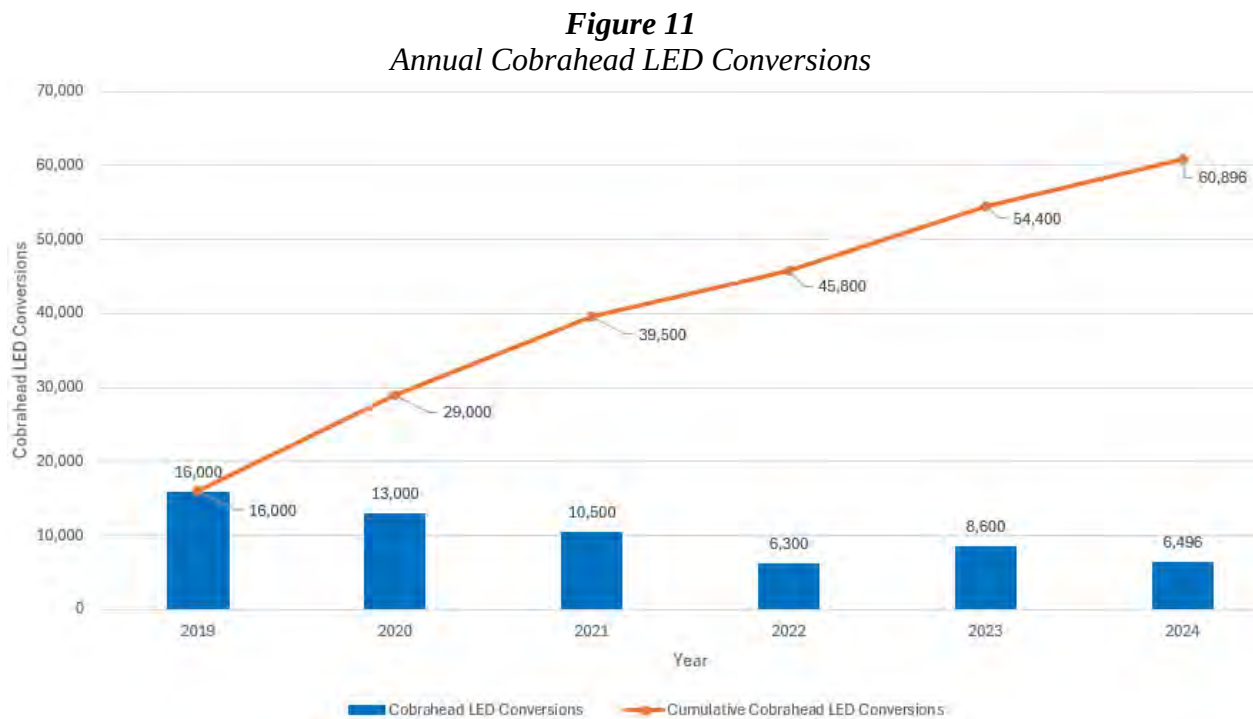
16 A. The Company calculated the five-year historical average capital expenditure amount for
17 the period from 2020 through 2024 and escalated that amount by an inflation rate of 2.1%
18 for 2025, 2.4% for 2026, and 0.8% for 2027. The number of new business streetlights and
19 their unit costs are presented in Exhibit A-12 (DAS-1), Schedule B-5.9, page 2, lines 1
20 and 2.

V. **CONVERSION OF COBRAHEAD, POST TOP, AND
CENTER SUSPENSION STREETLIGHTS**

Q. Please describe the Company's project to convert cobrahead streetlights from HID to LED.

A. Beginning in fall 2018, the Company made the decision to reactively convert all failed cobrahead streetlights from HID to LED as previously discussed in my testimony.

Figure 11 below shows annual cobrahead LED conversions.



These reactive conversions are in addition to the MV conversions discussed later in this testimony. The Company expects that it will convert the remaining HID cobrahead fixtures over the next two to three years.

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1 **Q. Why would the Company expect that all of its HID cobrahead fixtures would fail over**
2 **the next two to three years?**

3 A. The lamps on the HID fixtures are rated for 24,000 hours of service. With approximately
4 4,200 hours of lighting service annually, the average life of the lamps is approximately six
5 years.

6 Because the Company discontinued the repair and began to convert all failed
7 cobrahead HID fixtures to LED technology in 2018, it is reasonable to expect all remaining
8 HID fixtures would fail in the next two to three years.

9 **Q. How is the projected streetlighting expenditure level aligned with the Reliability**
10 **Roadmap?**

11 A. As described in the Reliability Roadmap (Exhibit A-129 (MPK-19)), these expenditures
12 are essential to extend the lifecycle of luminaires and reduce repair expenses across the
13 Company's streetlight portfolio. Conversion of post top luminaires to LED technology
14 increases their lifecycle, thereby reducing future outages. Vicinity conversions of
15 cobrahead and post top luminaries prior to failure increases the efficiency of field personnel
16 to reduce to the cost of conversions and, effectively eliminates near-term outages.

17 **Q. Is the Company proposing a change to the cobrahead vicinity conversion program?**

18 A. Yes. The Company will continue to convert HID cobrahead fixtures in the vicinity of failed
19 cobrahead fixtures. The Company will target 260 cobrahead vicinity conversions per year,
20 recognizing outage restoration is of higher priority than a conversion of a luminaire that
21 has not failed. Average outage restoration has degraded 4.92 days since 2023. Reducing
22 the Company's vicinity conversion target will provide additional flexibility to address
23 failures in a timelier manner while providing customers the benefit of a reduced conversion

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1 cost and avoided future outages. Improved focus on demand failure restoration, resulting
2 in a reduced average outage duration, is the primary driver of reducing the vicinity
3 conversion plan.

4 The Company has performed an evaluation of three cobrahead conversion options:
5 reactive, planned, and lights in the vicinity. A summary of the projected unit costs
6 associated with each option is shown in Table 3 below.

Table 3
Cobrahead Conversion Projected Unit Costs

Reactive Conversion	Planned Conversion	Vicinity Conversion
\$732.00	\$684.06	\$616.94

7 The reactive conversions have the highest unit cost but are a necessity as the light has
8 already failed and requires attention. The incremental cost to convert the failed light to
9 LED is essentially the cost of a vicinity conversion as travel time to the light cannot be
10 avoided.

11 **Q. Are all of the currently installed LED fixtures a result of the Company's reactive**
12 **conversion program?**

13 **A.** No. The Company effectively completed its planned MV conversion program in 2020. In
14 the last decade, the Company has reduced its quantity of MV luminaires from more than
15 63,000 luminaires to approximately 1,200 luminaires, all of which are center suspension
16 streetlights that I will discuss later in this testimony. At the beginning of the MV
17 conversion program, the MV luminaires were converted to HPS, however in recent years
18 the MV luminaires have been converted to LED. The Company also installed customer
19 requested new LED lights as well as any customer requested conversion of existing HID

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1 fixtures to LED. Figure 10 above represents the Company's historical progress and
2 illustrative continued progress.

3 **Q. What are the projected investments for all streetlight failures?**

4 A. Projected streetlight failure expenditures are summarized in Table 4 below.

Table 4
Projected Streetlight Failure Expenditures

Period / Year	Amount	Units
Bridge Period (ending 4/30/2026)	\$20.229 million	20,028
Test Year (ending 4/30/2027)	\$11.800 million	13,800

5 These projected quantities include all fixture types including cobrahead, center suspension,
6 post top, and floodlights.

7 **Q. How did the Company develop the projected capital expenditures for streetlighting**
8 **demand failures?**

9 A. The projected number of demand failures was based upon the number of capital streetlight
10 demand failures for the period from 2019 through 2023. This figure was increased to
11 include post top LED conversions as described in the Company's Reliability Roadmap
12 (Exhibit A-129 (MPK-19)). These figures were then multiplied by a projected unit cost for
13 reactive conversion. The number of demand failure streetlights and their unit costs are
14 presented on Exhibit A-12 (DAS-1), Schedule B-5.9, page 2, lines 9 and 10.

15 **Q. Can you explain what you mean by planned and reactive conversions?**

16 A. Yes. Planned conversions are performed on HID lighting that have not yet failed. The
17 Company's reactive program, in contrast, will perform its HID to LED conversions on
18 cobrahead fixtures, post top fixtures, and center suspension fixtures that have failed in
19 service. The Company's standard practice since 2018 had been to only convert cobrahead
20 fixtures upon failure; however, the Company extended that practice to center suspension

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1 fixtures beginning in 2022, and post top fixtures in 2024. The preferred method for
2 conversion of center suspension failures will be through the use of a direct replacement
3 LED at failure, as discussed later in this testimony.

4 In addition, as previously discussed, the Company began to convert HID cobrahead
5 fixtures in the vicinity of failed cobrahead fixtures in April 2022, and HID post top fixtures
6 in the vicinity of failed post top fixtures in February 2025.

7 **Q. Why did the Company originally choose to convert its cobrahead streetlights from**
8 **HID to LED on a reactive basis versus a planned basis?**

9 A. There were significant benefits to offering a reactive LED conversion program to address
10 the concerns the Company has heard from a number of its streetlighting customers. The
11 feedback the Company received from its customers was that they wanted to move to LED
12 lighting versus the existing HID technology as quickly as possible. The Company also
13 received feedback that many of its customers did not want to pay total project cost for the
14 planned conversions or for conversions at all. Many municipal customers operate under
15 very tight budget constraints and may not have the available resources to execute on a
16 community-wide planned replacement of all their streetlights, which would require a
17 significant up-front customer contribution. Replacing lights on a reactive basis means that
18 customers do not require any up-front contribution.

19 **Q. What were some of the other considerations with a reactive conversion approach?**

20 A. With a service territory of approximately 28,000 square miles, and more than 800
21 streetlighting customers, a planned approach to converting streetlights would unnecessarily
22 advantage certain customers over others. In addition, and as previously discussed, the rated
23 life of the HID lamp is 24,000 hours and, as a result, the Company knew it would visit the

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majority of HID cobrahead streetlights over seven years for lamp replacement and/or complete luminaire replacement. Since the Company already had to visit the light due to its operational status, it made sense to simply convert the light upon failure rather than make a separate trip to the light to convert on a planned basis. As a result, the Company made a decision to embark on a program to replace all HID cobrahead luminaires upon failure. This balanced approach was deemed to be fair and equitable because it provides each community with the benefit of LED lights at approximately the same conversion rate, absent an up-front cost to the customer. Therefore, the benefits and costs of the investment into streetlights is equally realized by all customers with this approach. In contrast, a Company-planned conversion with no up-front contribution would mean some communities are paying for others to realize the benefit of LED lighting while receiving no benefit themselves.

Q. Can you summarize the Company's selection of its reactive approach to cobrahead LED conversions?

A. Yes. Based upon the various factors that I have just discussed, including the cost comparison and the fact that the Company would already need to visit the majority of its HID cobrahead lights over five to six years since the inception of the program in 2018, the Company felt that its reactive conversion methodology upon failure provided a balanced approach to moving to LED streetlighting for all customers with no up-front contribution from customers. The Company's decision to also convert HID cobrahead lights in the vicinity of failed cobrahead streetlights is consistent with the intent of its original reactive conversion program and continues to be fair and balanced, will reduce the average cost per conversion, and will expedite the conversion process.

1 **Q. Has the Company previously evaluated other cobrahead streetlight conversion**
2 **models?**

3 A. Yes. In addition to the replacement of cobrahead streetlights upon failure and the
4 replacement of cobrahead streetlights in the vicinity of failed cobrahead streetlights, the
5 Company also considered the conversion of cobrahead streetlights on a planned basis.
6 Although the Company made the decision to go with its approach of replacing cobrahead
7 streetlights upon failure as its preferred approach, customers who want to convert their
8 cobrahead streetlights in a planned fashion still have that option as long as they pay for the
9 upfront conversion costs.

10 **Q. What is the Company's priority with respect to reactive cobrahead streetlight**
11 **conversions?**

12 A. As discussed earlier in this testimony, the Company's focus is to address failed luminaires
13 to restore lighting to its customers as quickly as possible, which customers have indicated
14 they want and deserve, versus focusing resources on planned lighting conversions. The
15 additional conversion of cobrahead fixtures in the vicinity of failed cobrahead fixtures will
16 expedite the overall conversion process at a reduced cost, and will eliminate near-term
17 outage events for these lights.

18 **Q. Why does the Company convert post top streetlights from HID to LED?**

19 A. Post top luminaire vendors began to phase out production of HID luminaires and
20 components in 2021. By the end of 2023 all the Company's lighting vendors had
21 completely discontinued HID post top product offerings. Because post top HPS product
22 offerings are no longer an implementable solution, conversion to LED technology will

1 extend the lifecycle of the luminaire, and reduce the frequency of post top luminaire
2 outages.

3 **Q. Why has the Company chosen to convert its post top streetlights from HID to LED**
4 **on a reactive basis versus a planned basis?**

5 A. The reasons for choosing to reactively convert post top streetlights are similar to those that
6 I previously discussed regarding reactive conversion of cobrahead streetlights. Replacing
7 lights on a reactive basis is in line with customer feedback, and does not require any
8 up-front contribution from customers.

9 **Q. Why did the Company not move forward with conversion of its post top streetlights**
10 **from HID to LED when it began reactive conversion of cobrahead streetlights to**
11 **LED?**

12 A. The Company did not move forward with the reactive conversion of post top streetlights at
13 the same time as cobrahead streetlights because the Company recognized customers select
14 post top streetlights based on aesthetics and style, unique to their application and location,
15 and the Company wanted to evaluate and provide customers with the best LED post top
16 lighting options. After careful consideration of the LED options and an understanding of
17 what customers want, the Company chose two color options, amber (3000 Kelvin
18 Temperature) and white (4000 Kelvin Temperature) for newly installed lighting requests
19 and replacements of discontinued HID post top lighting. Lastly, cobrahead streetlights
20 were the Company's largest lighting class, and are primarily supplied via overhead
21 conductor. Post top streetlights represented a smaller percentage of the Company's
22 streetlights and are supplied via underground conductor. Customer sentiment was
23 favorable toward reactive conversion of cobrahead streetlights.

1 **Q. What were some of the Company's other considerations with a reactive conversion**
2 **approach for post top conversions?**

3 A. The other considerations with a reactive conversion approach for post top conversions are
4 similar to those I previously discussed regarding cobrahead conversions. A planned
5 approach to converting streetlights would unnecessarily advantage certain customers over
6 others. This balanced approach is fair and equitable because it provides each community
7 with the benefit of LED lights at approximately the same conversion rate, absent an
8 up-front cost. Therefore, the benefits and costs of the investment into streetlights is
9 realized by all customers with this approach.

10 **Q. Can you summarize the Company's selection of its reactive approach to post top LED**
11 **conversions?**

12 A. Yes. The Company's selection of its reactive approach to post top LED conversions is
13 similar to its selection of its reactive approach to cobrahead LED conversions, which I have
14 previously discussed. The Company has deemed that its reactive conversion methodology
15 upon failure a balanced approach to moving to LED streetlighting for all customers with
16 no up-front contribution from customers.

17 **Q. Has the Company previously evaluated other post top streetlight conversion models?**

18 A. Yes. In addition to the replacement of post top streetlights upon failure the Company also
19 considered the conversion of post top streetlights on a planned basis. Although the
20 Company made the decision to go with its approach of replacing post top streetlights upon
21 failure as its preferred approach, customers who want to convert their post top streetlights
22 in a planned fashion still have that option as long as they pay for the upfront conversion
23 costs.

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1 **Q. What is the Company's priority with respect to reactive post top streetlight**
2 **conversions?**

3 A. As discussed earlier in this testimony, the Company's focus is to address failed luminaires
4 to restore lighting to its customers as quickly as possible, which customers have indicated
5 they want and deserve, versus focusing resources on planned lighting conversions.
6 Additional conversion of post top streetlight fixtures in the vicinity of failed post top
7 fixtures will expedite the overall conversion process at a reduced cost and will eliminate
8 near-term outage events for these lights.

9 **Q. How is the Company addressing the failure of HID center suspension streetlights?**

10 A. The Company has identified, evaluated, tested, and contracted for a direct replacement
11 LED center suspension fixture that will accommodate most center suspension streetlight
12 locations. The Company will use the direct replacement LED center suspension fixture as
13 its preferred replacement for center suspension streetlights. The Company expects it will
14 convert the approximate 11,000 HID center suspension fixtures to LED over the next two
15 to three years through its reactive replacement plan. Similar to the HID cobrahead fixtures,
16 the HID lamps are rated for 24,000 hours of service and, as a result, should experience
17 failure in five to six years based upon 4,200 hours of lighting service annually.

18 **Q. What is the Company's strategy regarding use of direct replacement of center**
19 **suspension streetlight fixtures?**

20 A. Since 2022, the Company's preferred option has been the use of direct replacement center
21 suspension streetlight fixtures because it is more economical and requires less intensive
22 construction methods to install. Situations may exist that require the relocation of center

suspension fixtures to the side of the road, however the Company will always attempt to use direct replacement center suspension fixtures upon failure.

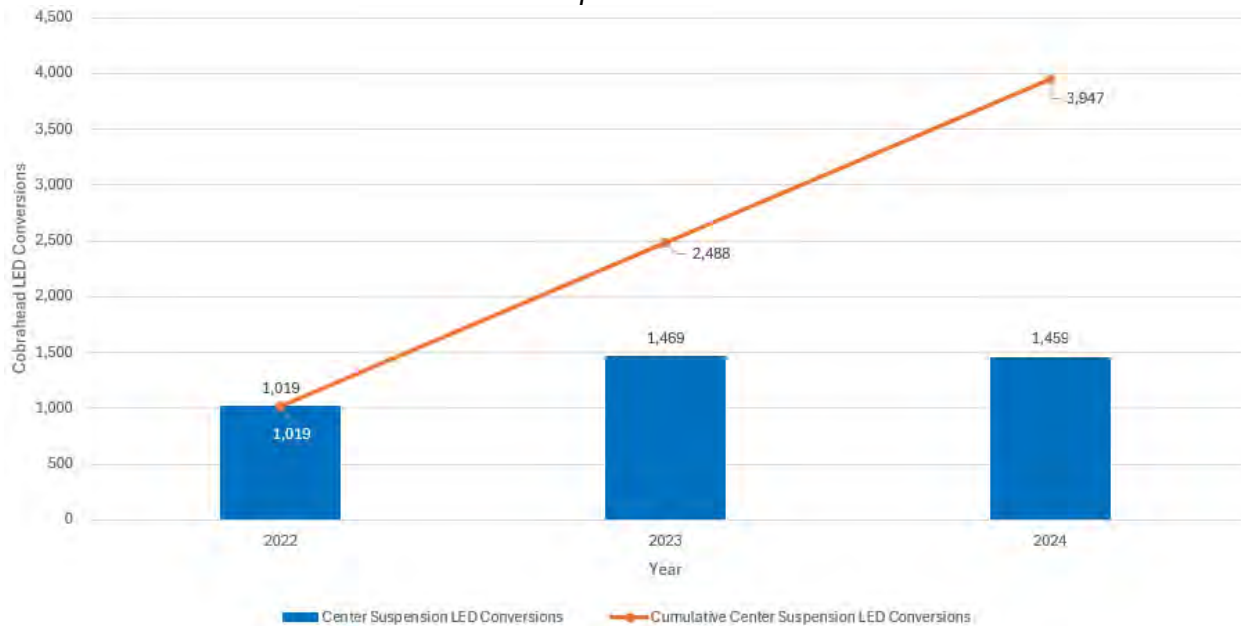
Q. What is the expected failure rate of the center suspension streetlights?

A. The Company expects center suspension streetlight failures to match the failure rate of cobrahead luminaires. With a total population of 11,000 center suspension installations across the state and an assumed 15% annual failure rate, the frequency of work in dangerous roadway situations is estimated at 1,650 lights annually.

Q. How many HID to LED center suspension conversions have occurred on an annual basis?

A. Figure 12 below shows annual HID to LED center suspension conversions.

Figure 12
Annual Center Suspension LED Conversions



VI. PLANNED STREETLIGHT CONVERSIONS

Q. Please describe the Company's planned conversions of cobrahead streetlights.

A. The Company will continue planned conversion of cobrahead streetlights located in the vicinity of failed cobrahead streetlights in 2025. The Company initiated planned

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1 conversions of cobrahead streetlights in April 2022. The planned conversion of cobrahead
2 streetlights will leverage the fact that the crews have already traveled to the location of a
3 failed cobrahead streetlight and, as a result, this will reduce truck rolls and indirect costs in
4 the replacement of the additional cobrahead fixtures in the vicinity of the failed fixture.

5 **Q. What is the expected reduction in truck rolls resulting from the conversion of lights**
6 **in the vicinity of failed cobrahead streetlights?**

7 A. As I will discuss later in this direct testimony, the Company is projecting it will convert
8 347 cobrahead streetlights in the 16-month projected bridge period ending April 30, 2026,
9 and 260 cobrahead streetlights in the projected test year ending April 30, 2027, which are
10 located in the vicinity of failed cobrahead streetlights. Table 5 below summarizes vicinity
11 conversion per year, by type. Because all of the cobrahead streetlight fixtures are expected
12 to fail in the next two to three years due to lamp life, the Company will avoid a future truck
13 roll for each cobrahead streetlight in the vicinity of a failed cobrahead streetlight. 347 truck
14 rolls are expected to be reduced in the 16-month bridge period ending April 30, 2026, and
15 260 truck rolls are expected to be reduced in the projected test year ending April 30, 2027.

16 **Q. How did the Company determine the projected number of cobrahead streetlights in**
17 **the vicinity of failed cobrahead streetlights?**

18 A. The Company used five years of historical failure data to project the number of failed
19 cobrahead fixtures. To accelerate the improvement in streetlight reliability, in alignment
20 with the Company's Reliability Roadmap filing, the Company increased its vicinity
21 conversion ratio to one vicinity conversion to one failed cobrahead.

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1 **Q. Please describe the Company's planned conversions of post top streetlights.**

2 A. Based on increasing HID post top product obsolescence, the Company began to reactively
3 convert post top streetlights in 2024 and execute planned conversions of post top
4 streetlights in the vicinity of failed post top streetlights in 2025. The planned conversion
5 of post top streetlights leverages the fact that crews have already traveled to the location of
6 a failed post top streetlight and, as a result, this will reduce truck rolls and indirect costs in
7 conducting the replacement of the post top fixtures in the vicinity of a failed fixture.
8 This workplan is described in Exhibit A-129 (MPK-19), the Company's latest version of
9 the Reliability Roadmap.

10 **Q. Has the Company changed the post top vicinity conversion program since the 2023**
11 **Reliability Roadmap filing?**

12 A. Yes. The Company will target 800 post top vicinity conversions per year, recognizing
13 outage restoration is of higher priority than a conversion of a luminaire that has not failed.
14 Average outage restoration has degraded 4.92 days since 2023. Reducing the Company's
15 vicinity conversion target will provide additional flexibility to address failures in a timelier
16 manner while providing customers the benefit of a reduced conversion cost and avoided
17 future outages. Improved focus on demand failure restoration, resulting in a reduced
18 average outage duration, is the primary driver of reducing the vicinity conversion plan.

19 **Q. What is the expected reduction in truck rolls resulting from the conversion of lights**
20 **in the vicinity of failed post top streetlights?**

21 A. As I will discuss later in this direct testimony, the Company is projecting it will convert
22 1,067 post top streetlights in the 16-month projected bridge period ending April 30, 2026,
23 and 800 post top streetlights in the projected test year ending April 30, 2027, which are

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located in the vicinity of failed post top streetlights. Table 5 below summarizes vicinity conversion per year, by type. Because all of the post top streetlight fixtures are expected to fail within approximately seven years of the start of the program due to lamp life, the Company will avoid a future truck roll for each post top streetlight in the vicinity of a failed post top streetlight. 1,067 truck rolls are expected to be reduced in the 16-month bridge period ending April 30, 2026, and 800 truck rolls are expected to be reduced in the projected test year ending April 30, 2027.

Q. How did the Company determine the projected number of post top streetlights in the vicinity of failed post top streetlights?

A. The Company assumed that all post top lamps would fail within seven years, equating to approximately 3,900 post top failures per year. Aligning with the cobrahead vicinity conversion tactic, the Company established a baseline that provides for conversion savings and future outage avoidance benefit for the customer.

Q. How did the Company develop the projected capital expenditures for vicinity conversions?

A. Based upon the projected material and labor costs, including loadings, the Company developed a projected cost per vicinity conversion of \$616.94 for cobrahead lights and \$1050.94 for post top lights. This unit price essentially eliminates the cost of a truck roll and travel time as compared to the unit cost for a reactive cobrahead conversion. Projected vicinity conversions by type are shown in Table 5 below. A summary of the projected unit costs associated with post top conversions is shown in Table 6 below. Projected vicinity conversion expenditures are summarized in Table 7 below.

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Table 5
Projected Vicinity Conversions by Type

Year	Cobrahead Vicinity Conversions	Post Top Vicinity Conversions
2025	260	800
2026	260	800
2027	260	800

Table 6
Post Top Conversion Projected Unit Costs

Reactive Conversion	Planned Conversion	Vicinity Conversion
\$1,166.00	\$1,118.06	\$1,050.94

Table 7
Projected Vicinity Conversion Expenditures

Period / Year	Amount	Units
Bridge Period (ending 4/30/2026)	\$1.334 million	1,413
Test Year (ending 4/30/2027)	\$1.018 million	1,040

1 **Q. What level of spending was included for rate recovery by the Commission in Case No.**
2 **U-21585 for the 14-month bridge period ending February 28, 2025 and test year**
3 **ending February 28, 2026?**

4 **A.** The Commission approved \$24.695 million for recovery in current rates for the 14-month
5 bridge period, and \$24.812 million for recovery in current rates for the test year.

6 **Q. What cost is the Company projecting for streetlighting capital investments in this case**
7 **for the 16-month bridge period ending April 30, 2026 and test year ending April 30,**
8 **2027?**

9 **A.** The Company is projecting \$26.432 million of streetlighting capital expenditures for the
10 16-month bridge period, and \$16.545 million of streetlighting capital expenditures for the
11 test year.

1 **Q. Please summarize the customer benefits of the Company's proposed streetlighting**
2 **capital expenditures.**

3 A. The Company's primary objective regarding streetlighting is to provide reliable service at
4 the lowest reasonable cost to customers. The Company carries out this objective through
5 conversions of older technology upon failure, installation of energy efficient lighting in
6 new applications, and use of self-service technology, which reduces work processing and
7 keeps the customer informed of streetlight outage status.

8 The Company is realizing the benefits of LED conversions through reduction of
9 failed streetlight orders. The workplan laid out in the Reliability Roadmap will only
10 accelerate this reliability benefit.

11 Performing cobrahead and post top LED conversions on a reactive basis provides
12 customers with LED lighting in a fair and timely manner, without the upfront costs.

13 **Q. Does this conclude your direct testimony?**

14 A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

ANDREW R. SNIDER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

INTRODUCTION

Q. Please state your name and business address.

A. My name is Andrew R. Snider, and my business address is 4000 Clay Ave, Grand Rapids, Michigan 49548.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”) as Executive Director of Electric Operations.

Q. Please describe your educational background and work experience.

A. I have a Bachelor of Business Administration from Davenport University in Grand Rapids, Michigan. I have been in the electric utility industry for more than 25 years. I began my full-time career with Consumers Energy in 1999 as an electric distribution designer and dispatcher. Through career progression in the Company’s Engineering and Operations departments, I currently serve as Executive Director of Electric Operations, with responsibility for Customer Field Services, Electric Meter Operations, Underground Construction, and Contract Management teams. I have been directly involved in service restoration activities, fulfilling nearly all back office and leadership roles within the storm restoration/Incident Command System (“ICS”) process dating back to my internship in 1998, supporting a back-office role for the largest storm in Company history. I served as a subject matter expert and project team member for the Outage Management System (OMS)/Responder project in 2008. I had the opportunity to represent Consumers Energy working on Florida Power and Light’s system following Hurricane Wilma, and on National Grid’s system following a severe winter storm. Today, I am supporting the Company’s initiatives to improve service restoration activities.

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1 **Q. What are your responsibilities as Executive Director of Electric Operations?**

2 A. I am responsible for leading Customer Field Services, Electric Meter Operations,
3 Underground Construction, and Distribution Contractor teams.

4 **Q. Have you previously provided testimony before the Michigan Public Service**
5 **Commission (“MPSC” or the “Commission”)?**

6 A. Yes. I was the Company’s witness for Service Restoration expense in Case No. U-21585.

7 **Q. What is the purpose of your direct testimony in this proceeding?**

8 A. The purpose of my direct testimony is to support the Company’s projected service
9 restoration spending, including technology and process enhancements. The test year is
10 defined as May 1, 2026 through April 30, 2027. In the test year, the Company projects
11 \$165 million in service restoration operating and maintenance (“O&M”) expense, which is
12 based on the Company’s actual 2024 Service Restoration expense, adjusted for inflation.
13 The projected test year expense is detailed further in the Service Restoration Test Year
14 O&M Expense beginning on page 20. Company witness Patrick D. Daly sponsors the
15 inflation rates. The service restoration O&M expense and O&M expense associated with
16 the Control/Dispatch Center consolidation project are included in Company witness
17 Michael P. Kelly’s Exhibit A-124 (MPK-14), and the Control/Dispatch Center
18 consolidation capital costs are included in Company witness Quentin A. Guinn’s Exhibit
19 A-102 (QAG-3). Information Technology costs addressed in my testimony are included
20 in Company witness Stacy H. Baker’s Exhibit A-12 (SHB-4), Schedule B-5.1, line 3.

21 **Q. Have you prepared any exhibits in conjunction with your direct testimony?**

22 A. No. I am not sponsoring any exhibits in conjunction with my direct testimony.

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1 **Q. How is your direct testimony organized?**

2 A. My direct testimony is organized as follows:

3 I. SERVICE RESTORATION OVERVIEW AND RECENT TRENDS

4 II. LIBERTY AUDIT OVERVIEW FOR SERVICE RESTORATION

5 III. SERVICE RESTORATION TEST YEAR O&M EXPENSE

6 IV. SERVICE RESTORATION RESILIENCY FUND

7 V. EXTRAORDINARY STORM ACCOUNTING

8 VI. TECHNOLOGY ENHANCEMENTS

9 VII. PROCESS IMPROVEMENTS TO BETTER IDENTIFY OUTAGE CAUSES

10 VIII. CONTROL/DISPATCH CENTER CONSOLIDATION

11 **I. SERVICE RESTORATION OVERVIEW AND RECENT TRENDS**

12 **Q. How does the Company's service restoration program benefit customers?**

13 A. Following service interruptions, the Company is committed to restoring service to
14 customers quickly and safely, regardless of the weather. Service restoration activities play
15 a critical role in the timely restoration of service to customers during outages. Timely
16 recovery of service restoration expense is essential to ensure resources are available to
17 restore service as quickly as possible, as the Company will be challenged to achieve further
18 improvements in storm restoration service if it does not have timely rate recovery for the
19 costs associated with such service.

20 **Q. The Company has been challenged by stakeholders to improve restoration efficiency.**
21 **Has the Company been able to demonstrate results?**

22 A. As predicted by our climate change and weather modeling, customers experienced another
23 record-breaking year in terms of response opportunities. The volume of interruptions in
24 2024 exceeded what mother nature delivered in 2023. In 2024, three catastrophic storms

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and two large gray sky events that occurred back-to-back in January, affecting 293K customers in one week, were the primary events. Despite the increase in storm activity and interruption volume, O&M service restoration costs decreased year-over-year from 2023 to 2024 by 17% with the cost per interruption decreasing by 18%.

Additionally, the Company's System Average Interruption Duration Index ("SAIDI") excluding Major Event Days ("MEDs") improved 21.4 minutes to 155, and all-weather SAIDI improved from 913 to 502.6 minutes. The improvements in service restoration are a result of both the distribution system investments sponsored by Company witness Kelly and the CE-Way process of continuous improvement that I discussed in detail in Case No. U-21585, and as shown in further detail in Figure 1 below.

Figure 1
2023 – 2024 Service Restoration Performance

Metric	2023	2024	Percent Change
Total Interruptions	50,700	53,900	6%
Percent Restored within 24 Hours	87%	94%	8%
Service Restoration Expenses	\$188 M	\$156 M	-17%

Q. How was the Company's service restoration performance in Environmental Justice ("EJ") communities in 2024?

A. In 2024, the Company's All-weather service restoration performance, restorations made within 36 hours, in EJ communities was 98.9% compared to 97.7% in Non-EJ communities. All-weather restoration performance in EJ communities in 2024 was 1.2% better than the Company's system average.

Figure 2
2024 Restoration Performance in EJ and Non-EJ Communities

Restoration Performance Metric	Non-EJ Communities	EJ Communities
Average percentage of all-weather restorations made within 36 hours	97.7%	98.9%
Average percentage of Catastrophic restorations made within 48 hours	95.4%	94.9%
Average percent of gray sky restorations made within 24 hours.	94.5%	93.2%

1 **Q. Has the Company started to incorporate considerations for EJ in their restoration**
2 **practices?**

3 A. Yes. In March of 2025, the Company developed reporting to provide increased visibility
4 into the identification of circuits in EJ communities that are experiencing outages. This
5 information is available in real time to the ICS teams and Grid Operators to assist with
6 restoration prioritization.

7 **Q. Is the Company satisfied with its holistic 2024 historical year performance?**

8 A. The Company is proud of the more efficient use of service restoration expenses and quicker
9 restoration times in 2024, but has several approaches aimed at further enhancing its
10 performance that are detailed later in my testimony. The Company acknowledges that even
11 with strong improvement in 2024, customers deserve an even more reliable grid than the
12 Company had last year.

13 The Company, including the Service Restoration team that I'm part of, has a more
14 aggressive goal for reliability as detailed in the Reliability Roadmap, which includes three
15 resiliency stands.

16 1. Delivering reliability performance into the 2nd quartile of nationwide utilities.

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2. Delivering a grid where no single outage event will affect more than 100,000 customers.

3. Delivering a grid where no customer will be without power for more than 24 hours following an outage event.

Achieving these goals remains a long-term work in progress; they serve as a useful guide to what the Company is building through this rate case.

Q. What weather challenges has the Company experienced so far in 2025?

A. The company has experienced two catastrophic storms already in 2025. Both storms affected more than 300,000 customers and occurred just six weeks apart. The first event was a historic multi-wave storm event that affected much of the state of Michigan from late March into early April that meteorologists from the National Weather Service called, “the worst ice storm in modern times.”¹

The event was so destructive that on March 31, Governor Whitmer declared a state of emergency in 10 counties in northern Michigan (Otsego, Oscoda, Montmorency, Presque Isle, Emmet, Charlevoix, Cheboygan, Crawford, Mackinac, and Alpena) and later extended the declaration to cover Alcona and Antrim counties. Several extreme weather factors, including freezing rain, damaging winds, thunderstorms, and 13 confirmed tornadoes made for a long and challenging restoration effort. Further detail on the timing and customer impact of the storms is detailed in Figure 3 below.

The event resulted in more than 8,500 outage incidents impacting over 380,000 Consumers Energy customers, the 7th largest storm by outages in the Company’s history. Icing on distribution and transmission lines, measuring up to 1.5” in certain areas, began March 31 and remained into Thursday, April 3, continually bringing down trees, power

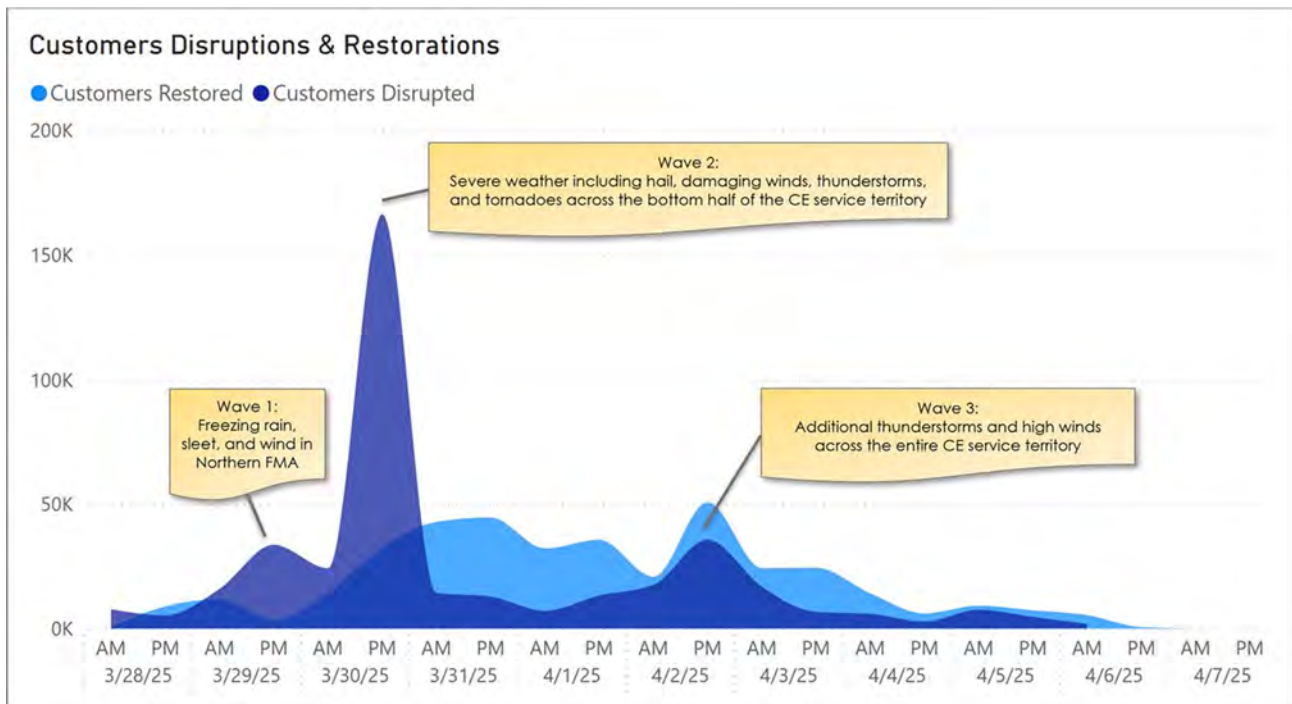
¹ Doyle, Annie. “‘A Generational Storm’: Northern Michigan Ice Storm Was Worst in over 100 Years.” Petoskey News-Review, 3 Apr. 2025.

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poles, and power lines, and delaying restoration crews' ability to make repairs due to the weight of the ice on the lines. The storm's severity and the subsequent evacuation of certain areas underscored the importance of Consumers Energy's enhanced Control Center Consolidation plan as discussed in section VII of my testimony.

The total cost of the storm is projected to exceed \$133 million (O&M and Capital), which is a significant portion of the Company's 2025 service restoration authorized spend from Case No. U-21585.

Figure 3
March/April 2025 Catastrophic Storm Disruptions and Restorations



The second event affected over 334,000 customers just six weeks after the historic icing event. On the evening of May 15th, a severe line of thunderstorms struck the State, leaving a wake of destruction. The massive line of storms produced 11 tornadoes and hurricane strength wind gusts from Holland to Battle Creek, ultimately resulting in over

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830 broken poles and 91 miles of conductor that required replacement. Total costs (O&M and Capital) from this event are estimated to exceed \$60 million.

Q. What has the Company learned from the recent catastrophic storms in Michigan and how is this reflected in your testimony?

A. The recent catastrophic storms have demonstrated the urgent need for timely rate recovery to keep the power on for customers, businesses, and communities, so the Company can respond to the ‘New Normal’ of severe storms in Michigan.

The climate and weather modeling has been acutely prescient in predicting increased severe storms in the Company’s service territory: the *Scenario and Investment Planning* section of the Reliability Roadmap included warnings of increased thunderstorms and ‘Other’ storms (including ice conditions) in the northwestern and southern parts of the Company’s service territory, primarily occurring during the winter when outages are typically more difficult to restore.

The modeling goes on to predict that this type of weather will become more frequent in the coming years, meaning the Company will likely have to protect and restore its customers from similar events on a more regular cadence. My testimony lays out Consumers Energy’s technological and operational initiatives to continue finding efficiencies as well as to ensure accurate restoration budgets and recovery of catastrophic storm spending through industry best practices.

Q. Please provide a brief overview of the remainder of your testimony.

A. Section II provides a detailed overview of Consumers Energy’s current event classification, resource identification, and pre-storm communication as well as several other operational and budgeting recommendations from the audit conducted by Liberty Consulting Group

1 (“Liberty”). Section III builds off the recommendations by Liberty, and details how the
2 Company’s bridge period and test year O&M was calculated in this case.

3 Sections IV and V include two new proposals to ensure the Company will have the
4 necessary rate recovery needed to continue providing both timely storm restoration and a
5 safe and reliable grid.

6 Sections VI, VII, and VIII detail the ongoing investments and process
7 improvements being made to further foster Consumers Energy’s storm restoration
8 efficiency through upgrades to its digital emergency response system and consolidation of
9 dispatch operations.

10 **II. LIBERTY AUDIT OVERVIEW FOR SERVICE RESTORATION**

11 **Q. Please describe the process leading up to the audit performed by Liberty.**

12 A. The Commission opened Case No. U-21305 in October 2022 after severe weather in
13 August of that year caused many long power outages, downed energized utility lines across
14 the state, and threatened public safety. In its order, the Commission instructed its Staff
15 (“Staff”) to hire a consultant to audit the electric distribution systems of Consumers Energy
16 and DTE Electric Company. The Commission directed the audit to consist of physical
17 inspection of the utilities’ distribution system infrastructure and investigation of the
18 utilities’ organization, staffing, and resources used to operate and maintain their
19 distribution systems and restore power when service is interrupted by severe weather. Staff
20 hired Liberty to audit the two utilities’ distribution systems, and the Company worked with
21 Liberty to promptly answer all written questions and transparently meet in numerous
22 interviews throughout 2023 and 2024. The Company also arranged Liberty’s physical
23 inspection and accompanied them as its auditors inspected pole locations, substations, the
24 Cadillac headquarters, and the Jackson distribution center. Following this process, Liberty

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1 released their final Utility Distribution Audit Report for the Company in two parts (“Final
2 Report”) on September 23, 2024.

3 In response to Liberty’s Final Report and stakeholder comments, the Company filed
4 comments and replies. Many recommendations in Liberty’s report were aimed at
5 improving the Company’s service restoration performance and had obvious merit, which
6 led the Company to begin making changes addressing these recommendations while it
7 awaits a final order in Case No. U-21305. As these changes impact proposals and expenses
8 in this case, I am updating stakeholders and the Commission on the Company’s progress.

9 **Q. Please describe the findings related to Pre-Event Planning from the Final Report.**

10 A. Part II of the Final Report included three recommendations specific to Pre-Event Planning
11 beginning on page 116, including:

- 12 • **Recommendation 4:** Better assure more tailored and accurate outage modeling
13 results by codifying and analyzing predicted versus actual outage events.
- 14 • **Recommendation 5:** Classify weather events no later than when the decision
15 is made as to whether available field resources will need to be supplemented
16 and as early as data permits a reasonable assessment of a weather event’s
17 impact.
- 18 • **Recommendation 6:** Capture and analyze data associated with external
19 resource requests.²

20 **Q. Please provide further details on Liberty Recommendation 4.**

21 A. Recommendation 4 proposes the Company evaluate its current outage model for
22 effectiveness and consider developing a more robust product in-house or through a
23 third-party vendor to provide more useful and impactful results.

² Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 116 (Sep. 23, 2024).

1 **Q. How has the Company's Service Restoration responded to concerns raised by**
2 **Recommendation 4?**

3 A. The Company agrees with the Final Report recommendation that accurate outage modeling
4 is critical for restoration staffing and planning for forecasted storm events and believes that
5 more accurate outage predictions can improve the Company's storm restoration
6 performance, including wire-down response.

7 The Company is currently working to improve its outage modeling results through two
8 additional initiatives, which will enable the Company to make improvements in outage
9 modeling capabilities:

- 10 • **New Third-Party Outage Model** – The Company is currently evaluating
11 third-party vendor technologies that could potentially improve upon its outage
12 modeling capabilities currently provided by IBM. The Company is currently in
13 a request for proposals phase with third-party vendors, which would merge its
14 weather and outage modeling services. The Company expects to select a
15 third-party provider in May 2025, and the Company expects that it will be able
16 to leverage the outputs of the third-party vendor's model later in 2025.
- 17 • **New In-House Outage Model** – The Company plans to internally develop a
18 standalone outage prediction model in partnership with the University of
19 Michigan. This in-house model would provide the Company with another set
20 of data to compare against outputs from the third-party outage model. Currently,
21 this model development is in its preliminary stages and is scheduled to be
22 operational by late 2025. Once developed, the Company would run the in-house
23 model concurrently with the third-party vendor model to compare results and
24 test its output to determine the in-house model's effectiveness and for potential
25 upgrade and/or waste elimination opportunities. In the testimony of Company
26 witness Scott A. McPhail, weather stations will be added to provide more
27 granular weather data that will eventually feed into the in-house outage model
28 offering improved predictive capabilities.

29 In summary, the Company agrees with this recommendation and has a series of technology
30 investment plans that will enable the Company to improve its outage modeling prediction
31 accuracy beginning in 2025. Furthermore, the Company will continue to assess the

1 predictions from these capabilities against actual outages to identify areas of improvement
2 to drive better prediction outcomes for future storms.

3 **Q. Please provide further details on Liberty Recommendation 5.**

4 A. Recommendation 5 proposes the Company make the act of event classification a catalyst
5 to groups involved in restoration to prepare to address the needs associated with the
6 anticipated impacts of the event and change, as necessary, after storm arrival, to reflect
7 new weather-related developments and resultant changes.

8 **Q. How has the Company's Service Restoration responded to concerns raised by**
9 **Recommendation 5?**

10 A. The Company has appropriate processes and procedures in place to meet the intent of this
11 recommendation. The Company understands the intent of this recommendation is to enable
12 efficient storm restoration preparation performance by potentially improving early storm
13 event classification, resource needs identification, and pre-storm communication processes
14 and procedures. While the Company welcomes opportunities to improve its storm response
15 preparation processes and procedures, there is more to the Company's current processes
16 than what is reflected in the Final Report for event classification, resource identification,
17 and pre-storm communication.

18 **Q. What is the Company's current process for event classification, resource**
19 **identification, and pre-storm communication?**

20 A. When preparing for a storm, the Company predicts an estimated number of outages from
21 its current IBM outage prediction model that will be experienced because of the potential
22 storm event.

1 The next step is to use its Catastrophic Crewing (“CatCrew”) tool to develop an
2 estimate of how many resources will be needed to complete the restoration within the
3 MPSC’s Service Quality and Reliability Standards for Electric Distribution Systems.
4 Based on this outage prediction and estimated resource needs, the Emergency Response
5 team then makes and communicates an event classification for the potential storm event.
6 On page 95 of the Final Report in Part II, Liberty included a table with the storm incident
7 classification levels from the Company’s Storm Restoration Manual (“SRM”). Initial storm
8 classifications are documented on an ICS Form 201 for each storm event, which is available
9 to all storm responders in the ICS organization.

10 **Q. Concerning the Company’s current event classification and resource identification**
11 **processes, what else should stakeholders and the Commission know when evaluating**
12 **the Final Report findings on these issues?**

13 **A.** There are several aspects of the Company’s current event classification and resource
14 identification processes and procedures that should be considered:

- 15 • Part II of the Final Report states on page 96 that “Analysis showed that
16 management did not classify any of these events prior to event start date.”³ All
17 initial storm classifications are documented on the ICS Form 201.
- 18 • The Final Report goes on to state on page 96 that “Consumers’ event level
19 classifications provide no specific guidance as to potential resource
20 requirements.” In fact, predicted customer outages and estimated resource
21 needs dictate storm event classification; storm event classification does not
22 dictate resource needs. In other words, storm event classification can only
23 happen when resource needs and customer outages have been estimated.
24 Additionally, the model being developed by the Company in partnership with
25 the University of Michigan will use sophisticated machine-learning techniques
26 to correlate historical outages to their causation (i.e., weather, topographic data,
27 forestry work, reliability work, etc.). This will produce a more accurate and
28 more localized outage forecast due to incoming weather that allows better
29 planning to secure and pre-stage resources for faster restoration.

³ Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 96 (Sep. 23, 2024).

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- Part II of the Final Report states on page 113 that “The storm team communicates internally to activate the required resources and processes without attaching value or significance to the determination and communication of an event’s classification. This view should change.”⁴ The value and significance of a storm event is the predicted customer outages and estimated resource needs, not the storm incident level by itself. While storm event classification may be useful as a trigger for certain storm related activities, the predicted customer outages and estimated resource needs is the foundational information that drives all storm restoration related activities.

Q. Please provide more details on the Company’s current storm communication process.

A. The Company currently plans for storm events on a weekly basis in advance to prepare for a weather event’s impact and communicates accordingly with its stakeholders. As recommended in the Audit, in November 2024 the Company hired a full-time Meteorologist to provide tailored weather forecasts, specific to the Company’s distribution grid and the state of Michigan, every morning to stakeholders across the Company. In terms of timing, every week the Company prepares for the subsequent week’s potential storm responders from an ICS perspective. This cadence includes an initial indication of what ICS Level the storm may be based on meteorological forecasts. Storm preparedness communications begin every Thursday and storm preparation related information is documented in ICS Form 201. Additionally, every day there is a Daily Communication Report that provides storm preparation and planning updates to relevant stakeholders across the organization. This information includes any changes to initial forecasts and updates to previous resource needs.

⁴ Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 113 (Sep. 23, 2024).

1 **Q. Concerning the Company’s current storm communication processes, what else should**
2 **stakeholders and the Commission know when evaluating the Final Report findings**
3 **on this issue?**

4 A. There are several aspects of the Company’s current storm communication processes and
5 procedures that should be considered:

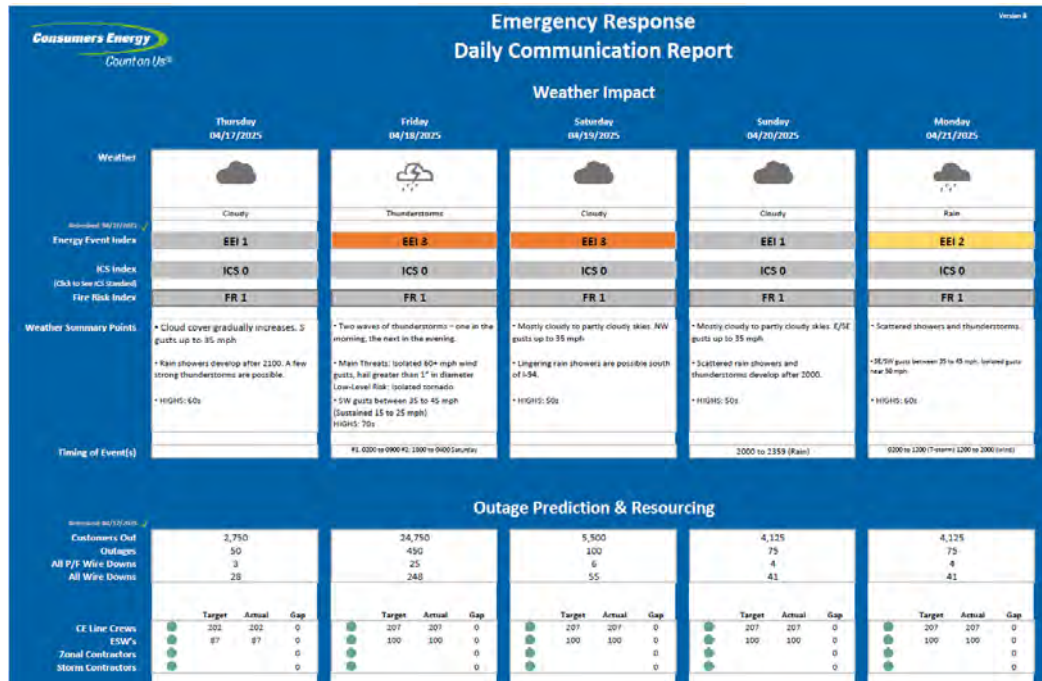
- 6 • Again, Part II of the Final Report states on page 96 that “Analysis showed that
7 management did not classify any of these events prior to event start date.
8 Neither did it change any classification for these events once made.”⁵ As
9 described above, storm event preparation and planning updates are
10 communicated daily to all stakeholders via the Daily Communication Report.
11 Based on changes communicated in this report, including event classification
12 changes, appropriate storm response related actions are made. The Final Report
13 does confirm this in another statement on page 96 that “Restoration
14 Management did . . . begin in late 2023 to publish a Daily Communication
15 Report that presents a five-day look ahead that contains, among other useful
16 information, outage prediction and resource requirement data and an ICS
17 incident level prediction. See Figure 4 below.”⁶

18 Furthermore, the Company does correct the ICS Level categorization data when it is
19 finalized for MPSC reporting purposes. For example, if a storm is initially reported as
20 affecting an estimated 190,000 customers and subsequent meter-ping data determines that
21 only 180,000 customers were affected, that information will be shared with the MPSC as
22 well if there is a relevant incident level adjustment. These updates are done across normal,
23 gray sky, and catastrophic storm conditions.

⁵ Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 96 (Sep. 23, 2024).

⁶ Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 96 (Sep. 23, 2024).

Figure 4
Daily Communication Report Example



Q. Please provide further details on Liberty Recommendation 6.

A. Recommendation 6 proposes the Company track resource requests from specific contractors (or mutual assistance), request timing, and what resources were provided to assist in post-event analysis, process improvement, and internal training.

Q. How has the Company's Service Restoration responded to concerns raised by Recommendation 6?

A. Since the execution of Consumers Energy's storm contracts which began on June 1, 2023, the Company has implemented or refined mechanisms to track, manage, and retain requests for resources to respond to service restoration events. These mechanisms include:

- A scorecard of all storm contractors to assist in acquiring resources by ranking the storm contractors in terms of lowest cost, proximity to Jackson, MI, number of full-time employees ("FTE") available to respond, and union/non-union status of their FTE's.

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- A managed PO Box where all communications pertaining to requests for assistance are kept.
- Centralized Microsoft Teams database maintained by the Company's Emergency Response organization. This database contains all current and past storm rosters of storm response contractors acquired since January 2022 to present, training standards, and documentation for Contractor Personnel Specialists responsible for acquiring storm response contractors.
- Bi-annual training for Contractor Personnel Specialists, along with on-demand training as standards are updated or improved.
- Ensuring the Company's storm response contractors have completed Consumers Energy's requirements for onboarding in ISNetwork prior to arrival on the system.
- Developing, designing, and delivering training to Company representatives responsible for oversight of storm contractors, including daily validation of crews and equipment acquired and working on Consumers Energy's system.

Q. Please describe the findings related to restoration budgeting from the Final Report.

A. Part II of the Final Report included two recommendations specific to restoration budgeting beginning on page 117⁷:

- **Recommendation 9:** Re-baseline restoration budgeting to produce estimates that fully and realistically consider expected needs; and
- **Recommendation 10:** Explore means to balance Company and customer interests in addressing highly volatile restoration costs following completion of the preceding recommendation addressing budgeting for storm restoration.

Q. Please provide further details on Liberty Recommendation 9.

A. Liberty's Recommendation 9 is a result of their Conclusion 15 in Part II, Chapter III, pages 114 to 115 which concludes:

It is not clear how a five-year average serves as a sound basis for setting budgets or a meaningful marker for sharing restoration costs that vary from five-year averages.⁸

⁷ Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 117 (Sep. 23, 2024).

⁸ Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, pages 114-115 (Sep. 23, 2024).

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1 Recommendation 9 states that reliance on the five-year average to fund service restoration
2 should end.

3 Reliance on five-year historical costs to establish restoration
4 budgets should end. Those responsible for managing
5 restoration cannot be held properly accountable for work or
6 costs performance if established budgets are known to be
7 unrealistic, fail to account for weather volatility, include
8 anomalous weather years within the five-year measurement
9 period, or rely on contributions from other parts of the
10 organization to accommodate not just expected, but
11 essentially certain overruns.⁹

12 Recommendation 9 also proposes the Company address how these system investments and
13 weather conditions will change through the timeframe included in the Reliability Roadmap
14 report.

15 **Q. Please provide further details on Liberty Recommendation 10.**

16 A. Recommendation 10 notes that service restoration expenses should theoretically trend
17 downward in response to reliability and resiliency investments. However, those
18 improvements may be offset by worsening weather:

19 Most significantly, the use of five years of historical
20 restoration costs as a benchmark for sharing between the
21 Company and customers ignores the fact that the system will
22 steadily respond better as time passes to outages that require
23 material restoration. It should not be taken for granted that
24 escalation and worsening weather will overcome the
25 reliability and resiliency gained by billions of dollars spent
26 over that historical period....¹⁰

27 Short of completing a full analysis that normalizes weather conditions and quantitatively
28 assesses how the Company's investments will interact with weather conditions to impact
29 storm restoration costs, as Liberty suggested in Recommendation 9, Recommendation 10

⁹ Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 117 (Sep. 23, 2024).

¹⁰ Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 118 (Sep. 23, 2024).

1 includes a deferral alternative. Liberty noted that other state regulatory commissions have
2 found deferral an effective means for permitting recovery of excess storm costs coupled
3 with a reasonableness and prudence review.

4 **Q. How is the Company's Service Restoration proposal responsive to concerns raised by**
5 **Recommendations 9 and 10?**

6 A. The Company's proposed bridge period and test year O&M expense aligns with Final
7 Report recommendations by ending reliance on a five-year historical average and instead
8 basing the projected expense on the Company's 2024 actual Service Restoration expense
9 adjusted for inflation. The Company believes this approach provides the most accurate
10 benchmark based on projected service restoration performance requirements. The
11 Company's Reliability Roadmap, included as part of this case as Exhibit A-129 (MPK-19),
12 already provides a normalized weather modeling forecast for the three scenarios
13 recommended by the Final Report. Further detail on the projected O&M spend, based on
14 2024 actuals, is included in the following section of my testimony.

15 **III. SERVICE RESTORATION TEST YEAR O&M EXPENSE**

16 **Q. What is the Company's projected service restoration O&M expense for the test year**
17 **in this case?**

18 A. The Company's projected service restoration O&M expense for the bridge period is
19 \$214.3 million and the projected expense for the test year in this case is \$165.2 million as
20 shown in Exhibit A-124 (MPK-14), line 22.

1 **Q. How did the Company determine this amount for projected service restoration O&M**
2 **expenses for the test year?**

3 A. Part II, Chapter III, page 110 of the Final Report states that:

4 Consumers plans very large capital and O&M expenditures
5 to improve system reliability and resiliency over the course
6 of five years. It has already achieved improvements to date.
7 Those improvements should, all else being equal, lower
8 restoration costs for a system steadily and materially
9 improving in reliability and resiliency, **making historical**
10 **costs a lagging, and not a leading indicator of likely costs.**
11 Factors that make all else unequal include escalation that
12 will affect the unit cost of each piece of equipment installed
13 and each quantity of work performed. Should recent storm
14 frequency and magnitude trends reverse, more extreme
15 weather will also drive costs upward, albeit moderated by an
16 increasingly “strong” system. Storm restoration costs have
17 proven highly volatile throughout the industry.¹¹

18 Given that 2024 O&M spending is a lagging indicator (although with far less lag than the
19 five-year average), the bridge period and test year funding was calculated by inflating the
20 historical year 2024 for the years 2025, 2026, and 2027. For the bridge period, the
21 calculation includes all of calendar year 2025, plus four months of 2026, the sum of which
22 equals the bridge period amount of \$214.3 million. The calculation for the test year
23 considers eight months of the year 2026 and four months of the year 2027, the sum of
24 which equals the test year amount of \$165.2 million. The inflation rates for the years
25 mentioned above are sponsored by Company witness Daly.

¹¹ Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 110 (Sep. 23, 2024) (emphasis added).

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1 **Q. What is the most recent five-year average for Service Restoration, and would that**
2 **amount be adequate for the Test Year in this case?**

3 A. Service Restoration has been underfunded in each of the previous five years, for a total
4 funding gap of \$351 million. The most recent five-year average from 2020 through 2024
5 would have produced a test year total of approximately \$148 million that the Company
6 projects would be insufficient to deliver the improved service restoration that customers
7 deserve. To illustrate the point, the March/April catastrophic storm that I described earlier
8 is projected to cost at least \$133 million dollars combined O&M and Capital. As explained
9 in detail in Section I of my testimony, the actual expenses from the calendar year 2024
10 were \$156 million, which were sufficient for the Company to deliver improved
11 performance on all restoration metrics. As the Company faces increasingly severe weather,
12 and progressive service restoration improvement metrics detailed in the Commission's
13 February 27, 2025 Order in Case No. U-21400, relying on a backward-looking average that
14 has been explicitly rejected by an independent audit threatens to undo the progress made
15 by the Company.

16 **Q. Why are 2024 historical costs a reasonable benchmark for projected service**
17 **restoration expense?**

18 A. Prior year spending is the most accurate benchmark of trending weather and current system
19 capabilities, based on the unpredictable weather explained in the *Scenario and Investment*
20 *Planning* section of the Company's Reliability Roadmap beginning on page 18. This fact
21 is recognized in the order released on March 13, 2025 in Case No. U-21400 where the
22 Commission decided to benchmark all weather SAIDI on current year performance rather

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1 than the five-year average, as current year performance better reflects recent trends and
2 customer experience.¹²

3 A study, beyond the Reliability Roadmap, specific to annual restoration spending,
4 would be theoretical given the high volatility of key variables. The Company's
5 recommended approach is to re-baseline to the most recent year, which most accurately
6 represents all variables in their current state. Further, through the creation of the Resiliency
7 Fund outlined in Section IV, the Company ensures every dollar is allocated specifically for
8 customer service restoration or returned to customers as a credit.

9 **Q. Has the Company been prudent with restoration dollars by increasing efficiencies?**

10 A. Yes. The Company's results are demonstrated by its historic year's performance and
11 documented in Service Quality and Reliability Standards filings and discussed in Section I
12 of my testimony. In 2024, the duration of catastrophic storms in the Company's service
13 territory, as measured by the average length of storm days, was 3.3 days compared to a
14 five-year average of 5.4 days. This accounts for a 2.1 day or 61% reduction in catastrophic
15 storm duration resulting in a greatly improved customer experience.

16 Liberty also took note of our performance trend since 2017 concluding in Part II,
17 Chapter III, Pages 113 through 114 of its audit:

18 Consumer's restoration performance, measured by the
19 average duration of classified storm types, **shows marked**
20 **improvement in recent years across all storm**
21 **classifications except for Catastrophic.**¹³

¹² See Case No. U-21400, February 27, 2025 Order, page 30 ("The Commission agrees that performance on this [all-weather SAIDI] metric should be measured for the previous year only.")

¹³ Case No. U-21305, Liberty Audit Final Report Consumers Energy Part II, page 113-114 (Sep. 23, 2024) (emphasis added).

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1 In terms of catastrophic performance, and the data set studied by Liberty, recent storms
2 had caused more customer interruptions resulting in longer durations trends through 2023.

3 Liberty noted in Part II, Chapter III, page 110:

4 A Catastrophic storm's defining characteristic, a minimum
5 of 10 percent of customers affected, ensures a longer
6 restoration period as compared with those of smaller storms.
7 The unbounded upper limit on customers affected also tends
8 to produce a much greater variation in the numbers of
9 affected customers. The much longer duration of
10 Catastrophic storms and greater variations in duration
11 therefore come as expected.¹⁴

12 **Q. How does the Company's proposal align with the Liberty Audit recommendations for**
13 **Service Restoration?**

14 A. As mentioned earlier in my testimony, the proposed test year O&M proposal reflects the
15 2024 actual Service Restoration expense adjusted for inflation, which the Company
16 believes provides the most accurate benchmark for service restoration requirements.

17 **IV. SERVICE RESTORATION RESILIENCY FUND**

18 **Q. What is the Service Restoration Resiliency Fund?**

19 A. The Resiliency Fund ensures that every customer dollar allocated for service restoration is
20 used for service restoration or returned to customers as a credit. The Resiliency Fund is a
21 reserve of surplus service restoration dollars from any prior year that will be used as the
22 first source of funds when actual costs for service restoration exceed base spend levels. The
23 fund will be capped at \$30.7 million in the test year, with any dollars exceeding those levels
24 refunded to customers through a bill credit.

¹⁴ Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 110 (Sep. 23, 2024).

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1 **Q. Please provide an example of how this fund would operate.**

2 A. If this fund is approved, any unspent dollars from the approved amounts for the test year
3 would be transferred to the Service Restoration Resiliency Fund. Those dollars can be used
4 to support service restoration expenses in future years when additional funds are needed
5 and would function as the first option to fund any restoration activity beyond base funding
6 levels. Please see Company witness Foster's testimony on page 15 for more detail on the
7 accounting of this request.

8 **Q. Please walk through Scenarios 1, 2, and 3 from Figure 5 below.**

9 A. **Scenario 1** shows an underspend of \$40 million dollars in the test year resulting in a
10 transfer of \$30.7 million to the Resiliency Fund and a customer refund of \$9.3 million.
11 Since the Resiliency Fund cap is exceeded by this underspend amount, the remaining
12 \$9.3 million will be refunded to customers.

13 **Scenario 2** shows an underspend of \$20 million dollars in the test year resulting in a
14 transfer of \$20 million to the Resiliency Fund to be used for service restoration expenses
15 that exceed base spending. Since the Resiliency Fund cap is set at \$30.7 million, the
16 Resiliency Fund can accrue an additional \$10.7 million before there is a customer refund.

17 **Scenario 3** shows an overspend of \$5 million in the test year, resulting in no transfers to
18 the Resiliency Fund.

Figure 5 - Resiliency Fund Year One Example

Scenario	Base Funding Amount	Restoration Spend	Resiliency Fund Balance	Customer Refund
1	\$165M	\$125M	\$30.7M	\$9.3M
2	\$165M	\$145M	\$20M	\$0
3	\$165M	\$170M	\$0	\$0

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1 **Q. How and why was the \$30.7 million cap limit set?**

2 A. The cap limit was based on the average O&M costs for a catastrophic storm for the past
3 three historic years (2022, 2023, and 2024). The average storm cost was then adjusted for
4 inflation based on the 2.4% inflation rate supported by Company witness Daly as part of
5 this case. Because the weather is unpredictable, the Company set this limit to ensure that
6 the fund only preserves the dollars needed to respond to a single potential catastrophic
7 event, after which customers would see a financial benefit from the Company's efficiency.

8 **Q. Is there a precedent from other states for setting a cap on reserve funds for storm**
9 **restoration?**

10 A. Yes. The Massachusetts Department of Public Utilities ("DPU") approved a proposal by
11 National Grid to increase the available storm fund contribution to reflect average annual
12 storm expenses for the previous five fiscal years. Under the recently revised proposal, for
13 any storm in which National Grid incurs more than \$1.80 million in incremental O&M
14 costs, National Grid is permitted to access a storm fund for the deferred recovery and
15 reimbursement of the portion of the costs that exceed \$1.80 million up to \$30 million for a
16 single event. In its order approving National Grid's proposal, the DPU noted the proposed
17 storm fund will provide for adequate recovery of storm costs while promoting rate stability.
18 While the Company's proposal differs from the Massachusetts mechanism, which includes
19 a surcharge to collect a set amount of storm costs through rates, the concept of setting a
20 cap on funds reserved for future use is similar.

1 **Q. How is this proposal different from how underspends for service restoration are**
2 **handled currently?**

3 A. Currently, in the event of an underspend for Service Restoration, the Company would
4 re-allocate the O&M resources to other projects with no guarantee that customers would
5 see any reimbursement. If approved, this Fund would both earmark approved funds for
6 service restoration in the years to come when the need arises or be returned to the customer.

7 **Q. What is the likelihood that there will be any underspend in the test year in this case?**

8 A. Re-baselining suggests there is a higher likelihood of underspend. The Company knows
9 that weather is unpredictable; however, as Liberty noted, weather volatility should be at
10 least partially offset by system improvements.¹⁵ Coupled with the Company's restoration
11 improvements, the Company maintains that there is an increased likelihood of underspend
12 from the prior year baseline. It really depends on what nature delivers. Consumers Energy
13 estimates that, over time, reliability investments will ease restoration spending needs.
14 When the Company inevitably spends less than projected, customers are protected by the
15 designed nature of the Resiliency Fund.

16 **Q. Why is the Service Restoration Resiliency Fund good for customers?**

17 A. The Resiliency Fund comes at no additional cost to customers—it is simply a rainy-day
18 savings plan. The Resiliency Fund ensures all dollars allocated for service restoration are
19 spent on service restoration or refunded. This proposal, coupled with re-baselining Service
20 Restoration to prior year actuals, mitigates the need for expensive speculative studies on
21 how the system will perform given the multitude of variables, while ensuring that **all**
22 savings from prior year system improvements and efficiencies will be saved for outlier

¹⁵ Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, page 115 (Sep. 23, 2024).

1 restoration expenses in a future year. Together with annual re-baselining, customers will
2 see immediate benefits from any year's savings in the next baseline, while savings are also
3 captured in the Resiliency Fund for no other reason than to benefit customers, literally, on
4 a rainy day.

5 **V. EXTRAORDINARY STORM ACCOUNTING**

6 **Q. Please describe the Company's proposed Extraordinary Storm Accounting or "ESA."**

7 A. ESA allows the Company to use deferred accounting for service restoration costs for
8 extraordinary storms that exceed base spending levels. The Company defines
9 "extraordinary storms" as storms that cause at least 300,000 customer outages over a seven-
10 day period or that result in a State of Emergency declaration from the Governor's office.
11 A recent example of such a storm is the March/April catastrophic storm cited in Section I
12 of my testimony. Under the Company's proposal, expenses in response to extraordinary
13 storms would qualify for deferred recovery.

14 **Q. Please provide an example of how ESA would operate.**

15 A. If the Company experiences any emergency storm(s) described above that drives the actual
16 spend higher than the service restoration base spending level (as well as any dollars
17 available through the Resiliency Fund, if approved), the Company would seek deferred
18 recovery from the Commission by demonstrating the reasonableness and prudence of the
19 restoration expenses in a future rate case. Overspend costs not related to an emergency
20 storm would not be eligible for recovery under ESA.

21 As detailed above, spending below the approved spending level would be directed
22 back to service restoration or customer refunds through the proposed Resiliency Fund (if
23 approved).

1 **Q. How was the 300,000 customer outage over a seven-day period or State of Emergency**
2 **declaration threshold determined?**

3 A. The emergency storm threshold was designed to apply to uncommon storms, based on
4 objective metrics or independent third-party assessment, which cause the most restoration
5 work and costs to the Company. In reviewing historical restoration data, storms causing at
6 least 300,000 customer outages are rare occurrences that also correlate to a long restoration
7 time and high costs. The Company has only recorded 13 storms with at least 300,000
8 outages, and restoration efforts from those storms have averaged seven days in restoration
9 duration.

10 While the outage count is a useful proxy for restoration time and cost, it is not the
11 only indicator of damaging events. Isolated natural disasters, such as the tornadoes that
12 struck Kalamazoo in 2023, did not cause many outages, but caused considerable damage
13 to distribution assets, leading to a three-day restoration. The addition of an emergency
14 declaration from the Governor's office allows for an independent assessment outside of the
15 Company's control to also qualify an event as an "emergency storm."

16 **Q. Why is the proposed ESA necessary?**

17 A. Extraordinary storms, which present challenging restoration conditions and cause
18 significant damage to Company assets, are the main cause of increased service restoration
19 spending and pose the largest risk to sustainable service restoration operations. As
20 explained earlier in my testimony, the March/April storms qualify as extraordinary storms
21 that drained most of the service restoration O&M budget for 2025. When these storms pass
22 through the Company's service territory, even perfect execution of pre-planning and
23 restoration procedures can still result in a costly, multi-day restoration effort costing over

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1 \$100 million. As disruptive and costly as these storms are, they are fundamentally
2 unpredictable; it is impossible for the Company to know with any degree of certainty how
3 many of these storms will pass through its service territory, and therefore impossible to
4 accurately predict the resources needed to respond to them. Requiring the Company to bear
5 the full brunt of their impact in a single year without allowing for deferred storm
6 accounting, which recognizes the heavy costs the Company incurs to safely and quickly
7 restore power after extraordinary storms like these, is not only unreasonable but also
8 counterproductive to ensuring a reliable and resilient grid. Preparing for a future where
9 weather events like the March/April storms are more frequent requires establishing
10 deferred accounting where the Company can apply for timely rate recovery in response to
11 these events.

12 **Q. What were the findings of the Liberty Final Report related to deferred recovery for**
13 **excess storm costs?**

14 A. Liberty noted the current utilization of deferral accounting by other commissions in Part
15 II; Chapter III, Pages 118-119 of the Final Report, stating,

16 Deferral accounting for excess storm costs may offer a
17 solution for avoiding customer costs for adverse weather that
18 does not materialize, while preventing significant Company
19 economic loss when such weather requires significantly
20 more than costs included in revenue requirements for
21 ratemaking purposes. Other commissions have found
22 deferral an effective means for permitting recovery
23 following some form of reasonableness and prudence review
24 that considers conditions faced and the effectiveness of
25 efforts undertaken to address them.¹⁶

¹⁶ Case No. U-21305, Liberty Audit Final Report Consumers Energy, Part II, pages 118-119 (Sep. 23, 2024).

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1 **Q. Do other states use deferred accounting for O&M costs caused by severe weather?**

2 A. Yes. New Jersey is one example. In 2021, the New Jersey Board of Public Utilities
3 (“BPU”) authorized deferred accounting for storm costs in BPU Docket No. ER21050823,
4 with automatic qualification for specific storms and the ability for utilities to petition for
5 approval for other storms. The Board determined that the utilities’ costs for an individual
6 storm automatically qualify for deferred accounting if they incurred incremental costs of
7 \$300,000, and the storm caused 10% or more of the customers located in the service
8 territory to be without electric service. South Carolina is another example. In response to
9 standalone storms that devastated large portions of the Carolinas, the Public Service
10 Commission of South Carolina in 2019 authorized deferred accounting for incremental
11 storm damage expenses in Docket No. 2019-26-E.

12 **Q. Please walk through Scenarios 1, 2, and 3 from Figure 6 below.**

13 A. **Scenario 1** shows an overspend of \$30 million, driven by a \$50 million emergency storm
14 and resulting in a \$30 million deferred recovery request. Since the emergency storm costs
15 exceed the difference between the base funding amount and the actual restoration spend,
16 the Company will ask for deferred recovery for the difference. The Company will provide
17 the Commission with the total expenses in response to the emergency storm including
18 justification for their reasonableness and prudence.

19 **Scenario 2** shows no difference between the base funding amount and the total spend.
20 Since the calendar year budget was adequate to the restoration needs for the year, there will
21 be no ESA despite the presence of an emergency storm.

22 **Scenario 3** shows an overspend of \$10 million but since the overages are not a result of an
23 emergency storm, the ESA will not be available.

Figure 6
ESA Year One Example

Scenario	Base Funding Amount	Total Restoration Spend	Emergency Storm Costs	ESA Deferred Recovery Amount
1	\$165M	\$195M	\$50M	\$30 M
2	\$165M	\$165M	\$50M	\$0
3	\$165M	\$175M	\$0	\$0

1 **Q. What is the process in a year where customers experience emergency storm(s) and**
2 **spending is less than base funding?**

3 A. All underspend in service restoration will be allocated to the Resiliency Fund up to the cap
4 of \$30.7 million. Once the cap is reached, customers will be refunded as a bill credit as
5 described in section IV.

6 **Q. What if the Resiliency Fund has a balance large enough to cover overages caused by**
7 **catastrophic storms?**

8 A. In this circumstance, the Company will not use ESA. Resiliency Fund dollars will be used
9 first to supplement overages in restoration spending.

10 **Q. Can ESA function independently without the Resiliency Fund?**

11 A. Yes. ESA can function independently. If approved, the Resiliency Fund would serve as
12 the first source of excess service restoration funds in the event of an overspend; however,
13 it is not required for the Company's ESA proposal.

1 **Q. How is ESA different from the Service Restoration Cost Sharing Mechanism**
2 **(“SRCSM”) proposed in Case No. U-21585?**

3 A. ESA creates both a higher threshold for deferred recovery than the SRCSM as well as a
4 process for Commission approval and vetting of service restoration expenses. ESA is only
5 available for “extraordinary storms,” defined to limit the eligible expenses for deferred
6 accounting to storms that cause the most damage to customers and restoration work for the
7 Company. By narrowing the scope of storms that qualify for deferred recovery, the
8 Company can focus on meeting Commission-defined Service Quality and Reliability
9 Standards within the base spending levels and have faith that timely rate relief will be
10 available when needed. Secondly, ESA gives the last word on deferred recovery to the
11 Commission. When deferred costs are considered for recovery in a future case, ESA will
12 require the Company to demonstrate that all expenses in response to extraordinary storms
13 are reasonable and prudent. The explicit inclusion of Commission approval is intentional
14 and reflects the Company’s confidence in its service restoration practices and desire for a
15 collaborative process to address future emergency storms.

16 **VI. TECHNOLOGY ENHANCEMENTS**

17 **Q. Are there any Capital investments in technology that support Service Restoration?**

18 A. The Company is continuing to enhance the digital emergency response system by
19 completing the previously planned CatCrew and Advanced Distribution Management
20 System (“ADMS”) enhancements, as approved in Case No. U-21389. The Company is
21 also resolving the software obsolescence concerns of its integrated Tools for Operations
22 Application (“iTOA”), as referenced on page 39 of Company witness Baker’s testimony
23 and Exhibit A-84 (SHB-1), as approved in Case No. U-21585. The Company is proposing
24 a \$825,700 capital and \$660,500 O&M investment in the test year for the development of

1 machine learning / Artificial Intelligence (“AI”) digital tools to specifically support storm
2 response, as described on page 52 of Company witness Baker’s testimony and Exhibits
3 A-12 (SHB-4), Schedule B-5.1 and A-19 (SHB-3).

4 **Q. How will the digital tools and utilization of Machine Learning and AI benefit**
5 **customers?**

6 A. The Company has developed several use cases where machine learning and AI can assist
7 with faster and more consistent decision-making. Speed to execution is of critical
8 importance during restoration events, and AI’s unique availability to simultaneously
9 evaluate multiple datasets and assist with decision-making will reduce non-value-added
10 time during restoration. Furthermore, AI’s learning abilities enable decision-making to
11 continuously improve, are unaffected by turnover, and mitigate learning curves as people
12 transition from role to role.

13 **Q. What are the use cases for digital tools and AI?**

14 A. **Storm Declarations:** The Company already has clear standards for when a storm should
15 be declared based on system conditions and resource availability. The opportunity for this
16 use case is to build a prototype learning model that continuously optimizes when storm
17 activations occur. Many storm declarations are clear decisions when a major event occurs.
18 However, this use case will specifically help with the “borderline” decisions on blue sky
19 and gray sky days.

20 **Resource Planning:** The Company believes that AI can assist with modeling
21 resource needs based on weather forecasts. Today, the Company estimates the number of
22 interruptions and subsequent customer outages based on weather forecasts. AI could assist
23 with resource planning and optimize the Company’s resource plan in a learning model.

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1 The savings opportunity for this use case is centered around the efficient utilization and
2 mobilization of resourcing and precise pre-staging for events. The target is for the resource
3 plan to match the event size, thereby creating savings for customers by ensuring the most
4 efficient resource planning.

5 **Resource Utilization or Crew Movements:** The Planning and Operations
6 branches of the ICS teams need to make critically immutable and important decisions at
7 the onset of an event. Consumers Energy's initial response to an event is one of the largest
8 indicators of success. In large and catastrophic storms, where many headquarters have
9 significant resource needs and a limited resource pool, it's imperative the ICS teams
10 quickly assess the needs of 30 electric headquarters and allocate the available resources in
11 the most efficient manner. The allocation must consider the location of the resources in
12 proximity to the damage, the qualifications of the resources, knowledge of the system, and
13 regional complexity factors (vegetation density, snow cover, road infrastructure, voltage
14 differences) as these all affect the speed of restoration. For example, due to customer
15 density and geographic complexities, Grand Rapids recovers faster than West Branch given
16 the near-term weather forecast. Thus, it is critical not to move resources out of an area
17 with an imminent weather threat.

18 Consider a reality-based scenario with 400 pre-staged line crews, 200 available
19 forestry crews, 200 available wire-down resources, all in various locations around the state,
20 that need to be immediately allocated to 15 storm-affected headquarters. Statistically, there
21 are a near infinite number of solutions, but only **one** of those solutions is the most efficient.
22 The faster the "one" most efficient solution is identified, and crews are mobilized, the more
23 customers benefit in terms of duration and ultimately cost.

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1 The gravity of this use case is to optimize that decision-making so decisions are
2 made faster and result in more efficient outcomes.

3 **Asset Identification:** In 2024, the Company developed an asset identification AI
4 model that learned what problematic insulators on the HVD system look like. The model
5 then examined photographs from aerial patrols to identify the structures containing the
6 problematic insulators. A similar application could be applied to facility identification
7 during storm restoration. With a simple photo provided by a customer, AI could quickly
8 distinguish Company-owned facilities from third-party facilities and help prioritize wire-
9 down response, for example. An AI application could improve public safety and response
10 efficiency by routing resources faster to where they are most needed.

11 **Q. Would the Company deliver on all the above AI use cases if granted the requested**
12 **investment?**

13 A. All these AI use cases would contribute to the Company's service restoration processes as
14 forward-thinking, industry-leading tools. The capital investment needed to fund research
15 and development of the outlined use cases is small compared to the potential benefits. The
16 Company plans to prioritize these use cases in the order in which they are listed above.
17 The Company would begin with the Storm Declaration use case because the model has
18 fewer variables and would quickly move next to the resource planning and crew utilization
19 opportunities. The Company estimates an annual opportunity of reducing each medium-
20 to-catastrophic event by 4 hours, with an estimated savings of \$4.5 million annually with
21 the realization of all use cases.

1 **Q. Does the Company have experience with Digital Tools and AI?**

2 A. Yes. The Company has three strong examples of how digital tools and AI are benefiting
3 customers each day. The examples include: the estimated time of restoration (“ETR”)
4 model used in the Company’s outage map, the forestry workplan selection tool as discussed
5 by Company witness Pamela L. Bolden, and the insulator identification project I have
6 discussed.

7 **VII. PROCESS IMPROVEMENTS TO BETTER IDENTIFY**
8 **OUTAGE CAUSES**

9 **Q. How does the Company currently identify and classify outage causes on its system?**

10 A. When restoring power and responding to outages, the Company’s field employees diagnose
11 the outage causes and classify them using the Institute of Electrical and Electronics
12 Engineers’ (IEEE) standard outage cause codes, including the following: animals,
13 equipment, trees, unknown, and weather. While the Company utilizes the IEEE standard,
14 it recognizes there are opportunities to improve by relying less on “weather” and
15 “unknown” cause codes. More accurate outage cause code reporting will help the Company
16 as it analyzes its restoration performance and yield better data quality as it prepares its next
17 reliability roadmap.

18 **Q. In its distribution audit report, what did Liberty conclude about how Consumers**
19 **Energy identifies and classifies outage causes?**

20 A. On page 84 of Part I of Liberty’s Report, it observed that the “weather” cause code “masks
21 the actual cause of outages like trees, lightning, or ice” Similarly, it said that the
22 “unknown” cause code is not precise but nonetheless “accounts for 11 percent of total
23 interruptions.” Ultimately, on page 17 of Part II of Liberty’s Report, it concluded that

“weather” and “unknown” cause codes “diminish[] the effective[ness] of the analysis of outage causes necessary to identify and optimize solutions to address them.”

Q. Did the Company respond to these findings in its comments and reply comments in the distribution audit docket?

A. Yes, the Company agreed that there is value in reducing the use of “weather” and “unknown” cause codes and discussed the initiatives then underway to improve how it identifies and classifies outages. Among other things, the Company said that it planned to benchmark its performance against peer utilities and identify measures being taken in the industry to categorize outages. Further, to better comply with IEEE standards, the Company said it was making changes to training, controls, and other operational processes. For example, the Company revealed its plan to establish new quality assurance and quality control processes to monitor and improve how line crews, dispatchers, and other storm responders categorize outages in real time when responding to incidents.

Q. Do you have any updates on the Company’s progress?

A. Yes, the Company has engaged a third-party consultant to conduct the benchmarking that the Company described in its comments; this benchmarking is in-progress as of May 2025 and on-track to be completed before end of 2nd Quarter. The Company plans to complete process changes, including new quality assurance and quality control processes, by the end of the year. More accurate outage data will help the Company better plan its resources to restore power after outages while also enabling better planning for its Reliability Roadmap.

VIII. CONTROL/DISPATCH CENTER CONSOLIDATION

Q. Is the Company following through with its plan to consolidate dispatch operations?

A. Yes. The Company is transitioning to consolidate operations.

1 **Q. Have there been any adjustments to the plan?**

2 A. Yes. The Company has been diligent in using the Plan-Do-Check-Act methodology with
3 this project and has made enhancements to strengthen operational capabilities as a result.
4 During the execution phase, it was identified through employee feedback that there was a
5 risk of losing talent and that operational capabilities would be enhanced by staffing the
6 back-up location, rather than maintaining an unstaffed back-up location. While the decision
7 to staff the back-up location provides a better level of service and equitable cost avoidance,
8 and SAIDI savings, it has changed the scope of the project.

9 **Q. How are the operational capabilities enhanced by a staffed location that can serve as**
10 **a back-up?**

11 A. A staffed back-up location significantly boosts operational capabilities by providing a
12 reliable contingency plan in case of disruptions at the other site. This set-up ensures
13 continuity of operations by minimizing downtime and maintaining productivity to optimize
14 safe and timely restoration for customers. The presence of trained personnel at each
15 location allows for immediate response to emergencies, reducing the risk of operational
16 delays. Additionally, it offers flexibility in resource allocation, enabling the company to
17 adapt quickly to changing circumstances and maintain service levels. Overall, two fully
18 staffed locations strengthen the Company's resilience and operational efficiency. Various
19 companies have consolidated their control rooms into two manned centers for quick
20 back-up. Independent research organizations have evaluated these strategies, highlighting
21 benefits such as operational continuity, enhanced reliability, quick response, disaster
22 recovery, and improved security.

1 **Q. Please explain how staffing a back-up center increases operational capacity.**

2 A. Foundationally, the Company cannot operate without redundancy and must maintain a
3 back-up facility, which has always been part of its plan. Several intuitive benefits are
4 realized by staffing the back-up facility.

5 • **Seamless Transition:** No recovery time required for the loss of critical systems
6 at either facility, resulting in the seamless transition of operations without
7 impacting customers.

8 • **Human Resource Diversity:** Consolidating all operations into one geographic
9 location in the state requires a deep talent pool in one area. Sharing the staffing
10 needs between two facilities, in different locations, enables a more diverse and
11 deeper talent pool.

12 • **Operational Capabilities:** In emergency situations, the Company's dispatch
13 centers can partially support each other, thereby enhancing operational
14 efficiency to a limited extent. For instance, in early 2024, an emergency
15 required the evacuation of one dispatch center. The remaining center was able
16 to assume critical statewide dispatch responsibilities, maintaining some
17 continuity in service restoration efforts, and mitigating prolonged customer
18 outages. Similarly, during the severe weather event on April 2, 2025, tornado
19 warnings led to the evacuation of one dispatch center. Within five minutes, the
20 alternate center resumed ongoing storm restoration activities, preventing delays
21 in service restoration for the Company's customers. These instances highlight
22 the current back-up capabilities between the Company's dispatch centers. The
23 ability to back up non-dispatch functions, typically associated with monitoring
24 and controlling the electric grid at higher voltages, will be fully realized upon
25 the final control center consolidation.

26 **Q. Can you talk about the benefits that have already been realized from the work that**
27 **has been completed and detail the changes from previous cases?**

28 A. Customers have already benefited from \$3.4 million of avoided costs and a 4.1-minute
29 SAIDI reduction achieved during the transition and throughout 2024. Testimony in Case
30 Nos. U-21389 and U-21585 anticipated these avoided costs and SAIDI reductions, as
31 Company witnesses outlined the overall significant cost savings and SAIDI improvements.
32 Initially, the Company planned to establish one fully staffed control center and one
33 unstaffed back-up facility, which was expected to yield annual savings of \$8.6 million and

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1 reduce SAIDI by 15 minutes. The total project cost was estimated at \$17.2 million, with a
2 schedule spanning from 2023 to 2026.

3 The current filing proposes creating two fully staffed control centers, each capable
4 of functioning as a back-up for the other. This change is expected to yield annual savings
5 of \$10.2 million and reduce SAIDI by 20.8 minutes. The total project cost is now estimated
6 at \$30.6 million, with a schedule spanning from 2023 to the first quarter of 2027.
7 Additional information on the revised benefits can be found later in my testimony.

8 **Q. What milestones of this consolidation project have been completed as of the end of**
9 **2024?**

10 A. Milestones for this project can be grouped in three areas: Building & Facilities, Process
11 Efficiencies, and Resource Preparedness.

12 • Building & Facilities:

- 13 o Consolidated three dispatch centers into two, strategically located in
14 Jackson and Grand Rapids.
- 15 o Initiated asbestos removal and remediation efforts.
- 16 o Developed conceptual plans and cost estimates.
- 17 o Currently in the preparation phase for design and engineering.

18 • Process Efficiencies:

- 19 o Expanded Jackson's operating hours from 16 hours a day, five days a week,
20 to 24 hours a day, seven days a week.

21 • Resource Preparedness:

- 22 o Merged three operating groups into two: High Voltage Distribution and
23 Low Voltage Distribution, ensuring alignment with transitional roles.
- 24 o Operational responsibilities were adjusted to enhance efficiency and ensure
25 a smoother workflow. This approach helped maintain productivity and
26 adapt to new processes more effectively. By redistributing tasks and roles,
27 the team was able to minimize disruptions and optimize overall
28 performance during the transition phase.

1 **Q. Have any benefits been realized in 2024 because of the Control/Dispatch Center**
2 **Consolidation project?**

3 A. Yes, from January 1, 2024, to December 31, 2024, the Company achieved measurable
4 benefits, including:

- 5 • Cost Savings: Avoided \$2.483 million in service restoration costs.
- 6 • Cost Savings: Reduced \$0.9 million in Grid Operations Labor costs.
- 7 • Improved Reliability: Reduced all-weather SAIDI by 4.1 minutes due to:
 - 8 o Shortened storm durations through enhanced storm readiness.
 - 9 o Fewer activations of ICS responders.

10 Following the 2023 consolidation of three Dispatch Control Centers into two, the
11 Company adjusted operational boundaries, enabling both control centers to be fully
12 engaged in storm restoration efforts from the onset of an event. This strategic change
13 enhanced resource allocation, optimized service restoration, and lowered operational costs.
14 The implementation of 24/7 operations at one dispatch center in 2024, coupled with
15 continuous improvement initiatives, allowed the Company to leverage an expanded
16 management span of control and boost productivity during service restoration.

17 The operational efficiencies implemented enabled the two remaining
18 Control/Dispatch Centers to manage restoration efforts for larger-scale events more
19 effectively than before consolidation. As a result, the need for ICS responder activations
20 has decreased, further optimizing response efforts. Establishing two fully staffed facilities
21 is essential to ensure redundancy, enhance resilience, and maximize the benefits of
22 improved resource allocation and operational efficiency.

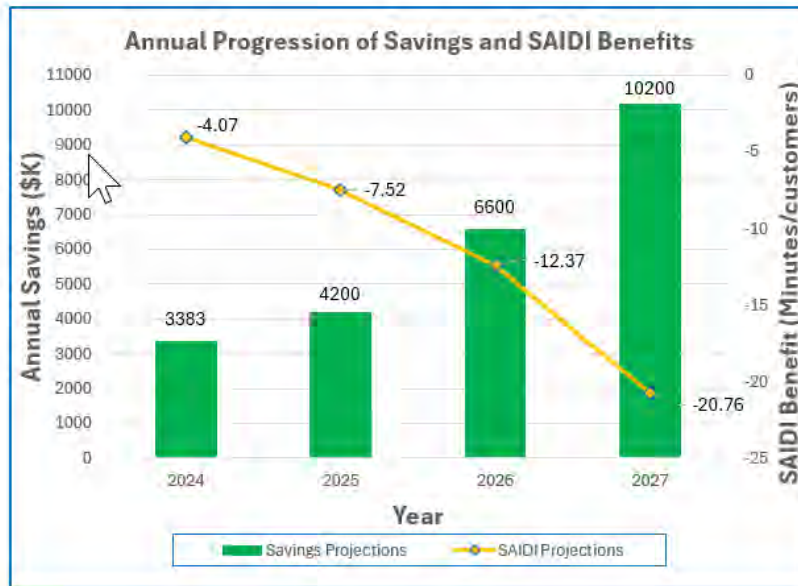
Q. What are the projected total cost savings and SAIDI improvements associated with this project?

A. Full benefit realization is projected by March 2028, one year following project completion. By this time, the Company expects to achieve:

- A sustainable reduction in all-weather SAIDI of 20.8 customer-minutes; and
- Annual cost savings of \$10.2 million through avoided operational expenses.

Figure 7 illustrates the ramp-up of these benefits, including those already realized in 2024.

Figure 7
Control/Dispatch Center Consolidation Project Annual Progression of Benefits



Q. Were there any adjustments to the original benefits filed in Case Nos. U-21389 and U-21585?

A. Yes, there were adjustments to the original benefits filed in Case Nos. U-21389 and U-21585. The initial projections for the Control/Dispatch Center consolidation project have been refined based on historical data from 2022–2023 and the realized benefits in the

historical test year 2024. These adjustments were necessary to provide a more accurate and realistic estimate of the project's impact on service restoration and outage duration.

Figure 8 summarizes the projected cost savings and all-weather SAIDI benefits, with column (c) reflecting revised figures and column (a) displaying the original projections.

Figure 8
Control/Dispatch Center Consolidation Project Benefits

Line No.		(a)	(b)	(c)
		Original Benefits	Adjustment	Revised Benefits
1	Service Restoration Cost Reduction	\$7.6M	\$2.5M	\$10.1M
2	Grid Operating Labor savings	\$0.9M	Realized in 2024	\$0M
3	Facilities / IT / expenses	\$0.1M	No Change	\$0.1M
4	Total Cost Savings	\$8.6M	\$2.5M	\$10.2M
5				
6	SAIDI Reduction	15 minutes	5.8 minutes	20.8 minutes

Q. Please explain the adjustments in the “Service Restoration Cost Reduction” category.

A. The initial estimate assumed a two-hour improvement in restoration time for both gray sky and catastrophic conditions. However, after reviewing historical data from 2022–2023, and analyzing realized benefits in the historical test year 2024, future projections have been refined to reflect a two-hour improvement for gray sky conditions and a 24-hour improvement for catastrophic conditions.

These adjustments are driven by increased use of technology, and additional operational efficiencies that have been identified, enabling faster and more effective power restoration. Key factors contributing to these efficiencies include clearer role alignment,

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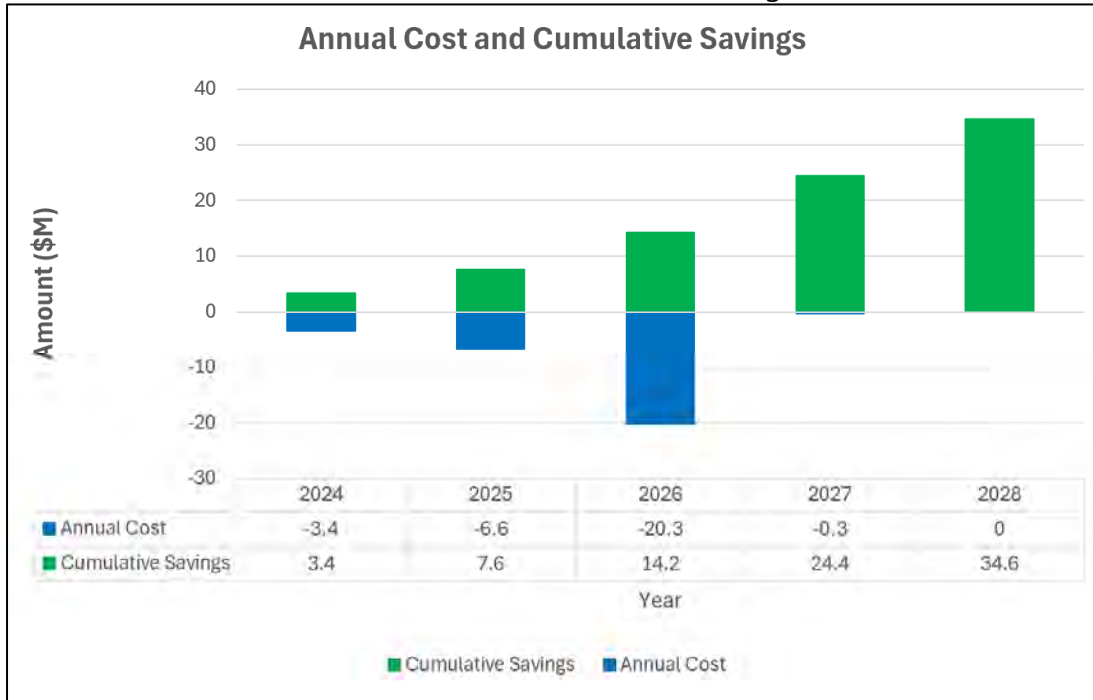
1 reduced operational hand-offs, co-locating operating groups within the same control center,
2 enhanced training for Grid Operators, and improved system-wide situational awareness.

3 **Q. What are the projected costs associated with this project?**

4 A. The Company projects a total expenditure of \$30.7 million for this project, including
5 \$15.8 million in the test year (\$15.5 million in capital and \$308,000 in O&M). These costs
6 support the completion of construction, commissioning, and occupancy of the operating
7 control centers by early 2027, as well as the integration of support group operations within
8 the consolidated control centers.

9 The capital costs for this project are detailed in Company witness Quentin A.
10 Guinn's Exhibit A-102 (QAG-3), page 1, lines 25 and 26, along with the associated
11 testimony. The O&M costs are provided in Company witness Kelly's Exhibit A-128
12 (MPK-18), line 27, and the corresponding testimony. Figure 9 illustrates the annual costs,
13 and cumulative savings for the project.

Figure 9
Control/Dispatch Center Consolidation Project Financial Overview:
Annual Cost and Cumulative Savings



The costs and benefits figures for this consolidation project represent a shift from testimony provided in previous rate cases as explained earlier in my testimony.

Q. During the historical year, how much was spent on the Control/Dispatch Center Consolidation project?

A. From January 2024 through December 2024, the Company incurred \$3.4 million in costs for the Control/Dispatch Center Consolidation project. These expenditures covered design services, material acquisition, and initial space renovations.

Q. Please summarize the Company's proposal for Control/Dispatch Center consolidation and its benefits for customers.

A. The Company's proposal involves consolidating the System Control, Distribution Control, and Dispatch Centers into two fully staffed control centers—one in Jackson and one in

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Grand Rapids. Each center will serve as a back-up for the other, with associated process and organizational changes delivering significant customer benefits.

Key Benefits:

- Annual Cost Savings:
 - o Service restoration annual cost reduction: \$10.1 million.
 - o Facilities/IT/Training expense annual savings: \$0.1 million.
 - o Total annual savings: \$10.2 million.
 - o A one-time Grid operating labor savings: \$0.9 million.
- Outage Response Benefit:
 - o All-weather SAIDI reduction: 20.8 minutes per customer.
- Project Cost and Implementation:
 - o Total cost: \$30.7 million (\$15.8 million in the test year).
 - o Completion timeline: Construction, commissioning, and occupancy of the two fully staffed control centers by early 2027, including the integration of support group operations.
- Initial Impact:
 - o 2024 results: \$3.383 million in cost savings and a 4.1-minute SAIDI reduction per customer due to process, organizational, labor reduction, and employee skilling improvements.
 - o Full benefit realization projected by March 2028.

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)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

SARA E. STEWART

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

SARA E. STEWART
U-21870 DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

2 A. My name is Sara E. Stewart and my business address is 1945 West Parnall Road, Jackson,
3 Michigan 49201.

4 **QUALIFICATIONS**

5 **Q. By whom are you employed and in what capacity?**

6 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
7 as Senior Manager of Forestry Operations.

8 **Q. Please describe your educational background and work experience.**

9 A. I have 11 years of utility experience at Consumers Energy within the Forestry Department
10 with extensive experience in the development and execution of the Line Clearing Program.
11 Over these years, I have held roles and performed the duties of all field and leadership
12 positions within the Forestry team overseeing strategy and operations, as well as driven
13 continuous improvement and technology enhancements including the development of the
14 forestry model and workplan selection tool. I am skilled in distribution, service restoration,
15 contract management, as well as financial management. I hold a Bachelor of Science
16 degree in Natural Resources and Environment from the University of Michigan with a
17 concentration on Resource Ecology and Management. I am an International Society of
18 Arboriculture Certified Arborist and Certified Utility Specialist. I also hold a Michigan
19 Department of Agriculture and Rural Development Pesticide Applicator Certification.

20 **Q. What are your responsibilities as Senior Manager of Forestry Operations?**

21 A. I have responsibilities for all forestry functions including line clearing, budgeting,
22 planning, and operations for the Company’s distribution system.

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1 **Q. Have you ever been a witness in a Michigan Public Service Commission (“MPSC” or**
2 **the “Commission”) case?**

3 A. No, but I have supported Pamela L. Bolden and Chris A. Shellberg as they prepared
4 testimony and exhibits in the last several rate cases: Case Nos. U-21585, U-21389,
5 U-21224, U-20963, and U-20697. Besides this, I participated in the distribution audit in
6 Case No. U-21305 by preparing responses to the Liberty Consulting Group’s (“Liberty”)
7 written audit requests and being interviewed and have had oversight of the Company’s
8 Line Clearing Program Annual Report and Line Clearing Program Formal Optimization
9 Analysis of Line Clearing Cycles in Case No. U-20697.

10 **PURPOSE OF DIRECT TESTIMONY**

11 **Q. What is the purpose of your direct testimony in this proceeding?**

12 A. The purpose of my direct testimony is to support the Company’s request in this case for an
13 increase in funding for its Line Clearing Program. My direct testimony is presented in six
14 sections: 1) Description of the Line Clearing Program; 2) Recent Progress of the Line
15 Clearing Program; 3) Vision for the Line Clearing Program; 4) Reliability Benefits of the
16 Line Clearing Program; 5) Expense Requirements for the Line Clearing Program Vision;
17 and 6) Resourcing Plan for the Line Clearing Program Vision.

18 **EXHIBITS**

19 **Q. Are you sponsoring any exhibits with your direct testimony?**

20 A. Yes, I am sponsoring the following exhibits:

21	Exhibit A-170 (SES-1)	Line Clearing O&M Expense;
22	Exhibit A-171 (SES-2)	Projected LVD Tree-Caused Reliability
23		Impacts of the Line Clearing Ramp-Up Plan;
24	Exhibit A-172 (SES-3)	2025 HVD Line Clearing Work Plan;

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1	Exhibit A-173 (SES-4)	2025 LVD Line Clearing Work Plan;
2	Confidential Exhibit A-174 (SES-5)	Post-Work Review Supporting
3		Documentation Examples;
4	Exhibit A-175 (SES-6)	Summary of O&M Expenses Projected
5		Using Inflation;
6	Exhibit A-176 (SES-7)	Formal Optimization Analysis of Line
7		Clearing Cycles; and
8	Exhibit A-177 (SES-8)	Utility Vegetation Management in North
9		America: Results from a 2019 Utility
10		Forestry Census of Tree Activities and
11		Operations.

12 **Q. Were these exhibits prepared by you or under your direction or supervision?**

13 A. Yes.

14 **DESCRIPTION OF THE LINE CLEARING PROGRAM**

15 **Q. Please explain the Company's Line Clearing Program.**

16 A. The Company's Line Clearing Program is responsible for maintaining clearance between
17 vegetation and energized equipment and to eliminate vegetation hindering accessibility to
18 the Company's electric lines. The Company uses Integrated Vegetation Management
19 ("IVM") along the Company's electric line rights-of-way to accomplish these objectives.
20 IVM is the practice of promoting compatible plant communities along rights-of-way using
21 a combination of cost-effective methods, including chemical, cultural, mechanical, or
22 manual treatments. This work is performed by contractors with qualified line clearance
23 tree trimmer employees, in accordance with Michigan Occupational Safety and Health
24 Administration (MIOSHA) requirements, on production-oriented contracts with the
25 Company. The Line Clearing Program is divided into two parts: (i) High Voltage
26 Distribution ("HVD") Line Clearing; and (ii) Low Voltage Distribution ("LVD") Line
27 Clearing.

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1 **Q. Please describe HVD Line Clearing.**

2 A. HVD Line Clearing manages vegetation along the Company's high voltage systems. There
3 are two major voltages on the Company's HVD system: 46 kilovolts ("kV") and 138 kV.
4 The Company clears vegetation within an 80- to 120-foot-wide right-of-way for these
5 voltages to attain a minimum of 15 feet of separation for 46 kV lines and 20 feet of
6 separation for 138 kV lines between conductors and vegetation at the time of clearing. The
7 Company also manages vegetation within the right-of-way to maintain accessibility along
8 the right-of-way for maintenance and repair of the line. During scheduled maintenance
9 line clearing, the Company identifies and removes hazard trees up to 40 feet from the edge
10 of the right-of-way. HVD Line Clearing is divided into multiple subprograms.

11 **Q. Please explain what projects, activities, and other types of work will be funded by**
12 **spending in HVD Line Clearing.**

13 A. HVD Line Clearing consists of an IVM program that promotes reliability by reducing
14 tree-caused outages and decreasing the impact of storms. HVD Line Clearing consists of
15 four subprograms: (i) maintenance clearing; (ii) brushing and herbicide treatment;
16 (iii) demand clearing; and (iv) noxious weed control (grass and weed mowing to meet local
17 ordinances). HVD Line Clearing also includes Forestry Operations Administration
18 expenditures.

19 The IVM program provides reliability benefit to customers while maintaining and
20 promoting a healthy ecosystem along the Company's HVD rights-of-way. The Company's
21 HVD and LVD rights-of-way are enrolled in the U.S. Fish and Wildlife Service's
22 Conservation and Consent Agreement with Assurances ("CCAA") for the monarch

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butterfly. The CCAA also requires protection for other pollinator species as well as threatened and endangered species that are found in these areas.

Q. What is HVD maintenance clearing?

A. The Company's HVD maintenance clearing work consists of scheduled cycle maintenance activity for trimming and removing trees within the right-of-way corridor and includes hazard tree removal outside of the right-of-way. HVD rights-of-way are typically cleared 40 feet on either side of the centerline to remove all tree species and shrubs that inhibit right-of-way access. Specimen trees growing along city streets or landscaped residential properties may be trimmed to attain a minimum of 15 to 20 feet of clearance instead of removal. A tree outside of the right-of-way is considered a hazard tree if it is tall enough to strike the HVD line if it fell and if it is dead, diseased, infected with destructive insects, or structurally weakened.

Q. What is HVD brushing and herbicide treatment?

A. The Company conducts brush cutting and herbicide treatment in HVD rights-of-way to reduce the volume of small trees growing within the right-of-way before they grow to a height that may interfere with the line. This work also allows line worker crews to access equipment for repair or replacement. Brush control work: (i) is completed on a four-year cycle schedule; (ii) reduces future stem volume; (iii) promotes the growth of compatible species within the right-of-way; and (iv) supports or maintains habitat needed for several endangered, threatened, or rare species of plants and animals.

Q. What is HVD demand clearing?

A. HVD demand clearing work addresses emergent vegetation threats to the Company's HVD system. These threats are identified by HVD vegetation inspections and by helicopter

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1 patrols of the HVD system. Demand clearing work most often involves partially uprooted
2 trees that are leaning towards the line that will eventually fall onto the line. These situations
3 require immediate remediation to prevent an outage.

4 **Q. What is HVD noxious weed control?**

5 A. The Company's noxious weed control work maintains compliance with local ordinances
6 for maintaining vegetation on fee-owned HVD rights-of-way in predominantly urban
7 areas. These ordinances do not permit vegetation growth above a specified height,
8 requiring three to six mowing cycles of affected rights-of-way each year, with variation
9 due to rainfall and temperature.

10 **Q. Please describe LVD Line Clearing.**

11 A. LVD Line Clearing manages vegetation along LVD primary voltage systems and
12 secondary voltage systems, including service conductors. The Company clears vegetation
13 within a 30-foot-wide right-of-way for primary voltages to attain a minimum of 10 feet of
14 separation between conductors and vegetation at the time of clearing and to maintain
15 accessibility along the right-of-way for maintenance and repair of the line. As a part of
16 LVD line clearing, hazard trees, such as dead or dying trees that are within 20 feet of the
17 edge of the right-of-way that are accessible to aerial lift trucks, are removed when not
18 objected to by the property owner. LVD Line Clearing is divided into multiple
19 subprograms.

20 **Q. Please explain what projects, activities, and other types of work will be funded by**
21 **spending in LVD Line Clearing.**

22 A. LVD Line Clearing consists of seven subprograms: (i) program maintenance (full circuit
23 clearing); (ii) repetitive outage zonal clearing; (iii) Customers Experiencing Multiple

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1 Interruptions (“CEMI”) clearing; (iv) first zone clearing; (v) Load Concentration Point
2 (“LCP”) zonal clearing; (vi) demand clearing (customer requested work); and (vii) brush
3 control. LVD Line Clearing also includes Forestry Operations Administration
4 expenditures.

5 **Q. What is LVD program maintenance (full circuit clearing)?**

6 A. LVD program maintenance clearing is the predominant, scheduled maintenance clearing
7 work for the LVD system. Trees are cleared to attain at least 10 feet of clearance to LVD
8 primary conductors. Secondary voltage conductors and services are cleared of any tree
9 limbs displacing or rubbing on these conductors. Brush (sapling trees and woody shrub
10 species) is cut within the 30-foot right-of-way. Hazard trees (dead, dying, or mechanically
11 stressed trees) within 20 feet of the edge of the right-of-way are removed when not objected
12 to by the property owner.

13 **Q. What is LVD repetitive outage zonal clearing?**

14 A. LVD repetitive outage zonal clearing targets specific sections of circuits that are
15 experiencing high levels of tree-caused outages. Monthly, the Company reviews sections
16 of circuits for multiple tree-related, non-Major Event Day (“MED”) outages within the
17 previous 12 months. Identified sections are scheduled for clearing based on system
18 reliability impacts and resource limitations. These sections are cleared to the same
19 specifications as program maintenance work.

20 **Q. What is LVD CEMI clearing?**

21 A. LVD CEMI clearing is designed to target customers experiencing high numbers of outages
22 during the current calendar year and reduce the likelihood that these customers will
23 experience similar outages going forward. CEMI clearing differs from repetitive outage

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clearing as CEMI is focused on the cumulative effect of all upstream LCPs from the customer's location, whereas repetitive outage is focused on the number of outage incidents in a particular LCP. For CEMI, no particular LCP may be experiencing outage rates at the repetitive outage level, but the cumulative effect of multiple upstream devices, each with just a few outages, results in the customer having many outages. CEMI clearing targets selected areas upstream of the customer location to reduce future tree-caused outages. CEMI areas may be cleared to the same specifications as program maintenance or select individual trees may be targeted for clearing depending on the vegetation conditions of the CEMI-identified section and the length of the section to be cleared.

Q. What is LVD first zone clearing?

A. LVD first zone clearing targets the section of a circuit from the substation outward to logical LCPs. Typically, these are three phase structures (poles with X, Y, and Z phasing) and any unfused laterals extending from this first zone. Although these zones may have lower outage frequency than other areas, outages that do occur impact a higher number of customers. This work reduces the likelihood of full circuit lockouts due to trees and provides a reliability benefit for all customers connected to the circuit. First zones are selected based on the previous 12-month tree-related outage history each fall when work plans are developed for the upcoming year. Clearing of first zones is targeted for first and second quarters of the work plan year to maximize the reliability benefit to all customers of the circuit. First zones are currently cleared to the same specifications as program maintenance with the exception that individual trees with overhanging branches regardless of clearance above conductors have been considered for 100% removal of these overhanging branches.

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1 **Q. What is LVD LCP zonal clearing?**

2 A. To comply with the Settlement Agreement for MPSC Case No. U-21224, the Company
3 incorporated LVD LCP zonal clearing as a new subprogram starting in 2024 that targets
4 the worst performing zones across the LVD system. In the 2024 calendar year, the
5 Company cleared 42 miles under the LCP zonal clearing subprogram. These sections are
6 cleared to the same specifications as program maintenance work. This subprogram differs
7 from the repetitive outage subprogram in that LCP zonal clearing work is evaluated and
8 added to the annual work plan at the beginning of the calendar year, whereas repetitive
9 outage work is evaluated monthly.

10 **Q. What is LVD demand clearing?**

11 A. LVD demand clearing addresses emergent vegetation threats to the LVD system.
12 Emergent vegetation threats are identified predominantly by customers calling in personal
13 observations around their homes, from forestry operations personnel, and from other
14 electric operations employees performing duties in the field. The Company's forestry
15 operations personnel review these requests in person, or through phone conversations, with
16 the reporting party to validate the emergent nature and the likelihood of an outage. Work
17 that can wait until maintenance clearing will be performed is delayed, but validated threats
18 to the system are prioritized and addressed based on potential system reliability impacts
19 and resource limitations.

20 **Q. What is LVD brush control?**

21 A. LVD brush control uses herbicide applications to treat brush within the LVD right-of-way
22 two to three years following full circuit clearing, particularly on rural and suburban circuits
23 with higher brush densities in the right-of-way. This work reduces future stem volume,

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promotes the growth of compatible species within the right-of-way, and helps maintain accessibility for line maintenance or repair. Brush growing in or near wetlands or open water bodies is manually or mechanically cut instead of being treated with herbicides.

Q. What standards apply for trimming trees along service lines?

A. Customer service lines are cleared of trees or parts of trees that are displacing or rubbing on these conductors. Service line clearing is identified and occurs during program maintenance (full circuit clearing) and other scheduled Operating and Maintenance (“O&M”) subprograms. The Company also addresses tree issues along service lines outside of scheduled O&M subprogram clearing on an emergent basis through its demand subprogram by removing trees or parts of trees that have fallen on service lines and trimming limbs that are causing damage to conductors.

Q. Does the Company perform quality assurance of line clearing work done in the field by contractors?

A. Yes. In accordance with Rule 505 of the Commission’s Technical Standards for Electric Service, Mich Admin Code, R 460.3505, as amended through MPSC Case No. U-20630, the Company performs quality assurance of line clearing work through its standard post-work review process for scheduled O&M projects. After planned line clearing work is completed, the contractor submits a Circuit Closing Form for each section of circuit. A statistically relevant representative inspection is then completed where the Company reviews the work in the field to ensure clearance is obtained and hazard trees are removed as planned. If trees, brush, or vines were missed by the line clearing contractor, tree crews are sent back to complete the work on non-billable time. Upon completion of this re-work, the contractor submits a Weekly Summary Crew Report identifying when, by whom, and

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1 with what equipment the non-billable work was completed. **Confidential** Exhibit A-174
2 (SES-5) contains documentation supporting this process. As an example, for scheduled
3 O&M work, the Company required 720 hours of non-billable labor in 2024 identified
4 through its post-work review process. It is important to note that the Company has internal
5 forestry operations personnel presence in the field as work is being completed by line
6 clearing contractors, which results in quality assurance checks and corrections throughout
7 work completion. It is in the best interest of the Company, its electric customers, and its
8 line clearing contractors to prevent defects and increase first-time quality of work, thus
9 driving down the number of defects discovered in post-work review and resulting
10 non-billable labor hours.

11 **Q. Does the Company's Line Clearing Program include clearing required for service**
12 **restoration?**

13 A. Forestry is a key piece of the Company's service restoration efforts. Forestry manages the
14 tree crews during restoration events, working together with many other areas of the
15 Company to restore service or address emergent threats to the system. The costs for this
16 work are captured in service restoration expenses. Service restoration expenses are
17 addressed by Company witness Andrew R. Snider and are not a part of the line clearing
18 funding discussed in my direct testimony. However, the funding requested for line clearing
19 establishes a base of tree crews working on the system that are utilized for service
20 restoration work when needed.

RECENT PROGRESS OF THE LINE CLEARING PROGRAM

Q. Please describe the Company's recent progress for its HVD Line Clearing subprogram.

A. The Company has continued to maintain a four-year clearing cycle for its HVD system. Figure 1 below shows five-year actual clearing and expenditure data and a summarization of the most recent four years of clearing towards the cycle.

FIGURE 1
HVD LINE CLEARING HISTORICAL CLEARING AND EXPENDITURES

Description	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	4-Year Cycle 2021-2024
Cleared Miles	1,116	1,178	1,106	1,153	1,203	4,640
Planned Miles	1,103	1,129	1,161	1,164	1,166	4,620
O&M Expense (\$M)	\$9.17	\$10.74	\$10.99	\$11.30	\$10.73	\$43.76
Planned O&M Expense (\$M)	\$9.48	\$12.60	\$11.71	\$12.06	\$12.28	\$48.65
\$/line mile	\$8,219	\$9,117	\$9,932	\$9,801	\$8,919	\$9,431
Clearing Cycle (years)	4.2	4.2	4.2	4.2	4.0	4.0

Q. Please list any prioritized projects for maintenance clearing work in the HVD line clearing subprogram for 2025.

A. In 2025, the Company is planning HVD line clearing on the lines listed in Exhibit A-172 (SES-3).

Q. Please describe the Company's recent progress for its LVD Line Clearing subprogram.

A. The Company has been working towards attaining a seven-year effective clearing cycle for its LVD system and has not yet attained this cycle. Figure 2 below shows five-year actual clearing miles, expenditure data, workplan backlog and cycle percentages, and a

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1 summarization of the most recent five years of clearing towards the seven-year effective
2 cycle target.

FIGURE 2
LVD LINE CLEARING HISTORICAL CLEARING AND EXPENDITURES

Description	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	5-Year Actual 2020-2024
O&M Cleared Miles	4,211	5,279	6,388	6,365	6,030	28,273
O&M Planned Miles	3,166	5,223	5,636	5,875	6,760	26,660
O&M Expense (\$M)	\$46.10	\$75.83	\$91.02	\$97.79	\$99.49	\$410.23
Planned O&M Expense (\$M)	\$41.36	\$71.43	\$81.49	\$87.97	\$105.37	\$387.62
\$/line mile	\$10,948	\$14,364	\$14,248	\$15,364	\$16,499	\$14,510
Effective Clearing Cycle (years)	13.1	10.6	9.1	9.2	9.7	10.1
Workplan Backlog Miles Percentage	98%	87%	67%	82%	80%	82%
Workplan Cycle Miles Percentage	2%	13%	33%	18%	20%	18%

3 **Q. Please list any prioritized projects for full circuit clearing work in the LVD line**
4 **clearing subprogram for 2025.**

5 A. Exhibit A-173 (SES-4) shows the 2025 LVD work plan which includes the forestry model
6 output circuits and circuits begun in 2024 with completion carrying over to 2025.

7 **Q. Please describe the seven-year effective cycle and how it works.**

8 A. The seven-year effective cycle describes a strategy of clearing one-seventh of LVD system
9 miles per year with different targeted cycle lengths of clearing for the three major primary
10 voltages on the LVD system. Upon achieving the seven-year effective cycle, 14.4/24.9 kV
11 circuits would be cleared on average between four to six years, 7.2/12.47 kV circuits would
12 be cleared on average between six to eight years, and 4.8/8.32 kV circuits would be cleared
13 on average between eight to ten years depending on the circuits' historical performance,
14 reliability predictions from the forestry model, and safety considerations. The Company
15 first used historic actual data in MPSC Case No. U-20697 to justify that the seven-year

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effective cycle was the most cost-beneficial approach to reducing tree-related outages on the LVD system at current system conditions. Figure 3 shows the annual clearing miles schedule required to maintain the seven-year effective cycle for the LVD system once it is achieved.

FIGURE 3
LVD CLEARING SCHEDULE FOR 7-YEAR EFFECTIVE CYCLE

Substation Voltage Class	Approximate System Miles	14% Clearing Program – miles/year cleared	Effective Cycle for Voltage Class
14.4 kV	18,000	3,600	5 years
7.2 kV	10,700	1,529	7 years
4.8 kV	32,300	3,589	9 years

Q. Has the Company made LVD line clearing specification changes in recent years?

A. Yes, the Company has made changes to its line clearing specification in recent years. In 2009, it added enhanced overhang clearance requirements for weak-wooded species overhanging primary wires from 15 feet to 20 feet. In 2016, the Company incorporated hazard tree removal as part of its base LVD primary line clearing specifications.

Q. What recent technology enhancements has the Company utilized in its Line Clearing Program?

A. The Company recently modernized its forestry model by harnessing more sophisticated predictive and prescriptive analytics in Machine Learning and satellite imagery analysis to influence and guide its LVD full circuit clearing subprogram. The forestry model has been built into a web-based tool, called the forestry workplan selection tool, to allow for a consistent, stable, and sustainable methodology to optimize the yearly LVD full circuit clearing workplan to capture the most reliability and safety benefit for annual spend. The output of the forestry model is an input into the forestry workplan selection tool. This new

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1 technology was first utilized to generate the 2023 LVD full circuit clearing workplan and
2 has continued to be used annually. The underlying forestry model that is built into the
3 forestry workplan selection tool is retrained on the most up-to-date data sources annually
4 for an updated risk assessment.

5 **Q. Please explain how the forestry workplan selection tool works and how it functions to**
6 **reduce tree-caused outages.**

7 A. The forestry workplan selection tool uses the output of the forestry model, which is a
8 Machine Learning model that uses hundreds of data inputs to predict tree-related reliability
9 impacts across the LVD system for the following year. Because an understanding of
10 individual circuit return on investment is necessary to capture the highest reliability benefit
11 for the spend, this selection tool includes the use of satellite imagery analysis to more
12 accurately project costs to clear them. Reliability predictions coupled with historical safety
13 performance (e.g., hazard events including trees on line, wires down, etc.) and cost
14 projections are then fed into an optimization engine with parameters identified (e.g.,
15 budget) to automatically generate a targeted LVD full circuit clearing workplan that
16 captures the highest amount of reliability and safety risk.

17 **VISION FOR THE LINE CLEARING PROGRAM**

18 **Q. What is the Company's vision for its Line Clearing Program?**

19 A. The Company's vision for its Line Clearing Program is simple: fewer tree-caused outages
20 on its system that will improve electric reliability for its customers in all conditions. To
21 achieve this, the Company is proposing to maintain a four-year clearing cycle for its HVD
22 system and, for its LVD system, proposing a ramp-up to a five-year clearing cycle and
23 performing more aggressive line clearing on targeted three phase primary lines. The

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1 proposed timeline to achieve the shortened line clearing cycle and scope of more aggressive
2 line clearing is targeted by the end of the 2030-2031 test period, which is a similar timeline
3 the Company proposed in MPSC Case No. U-21585 to achieve its previous seven-year
4 effective cycle strategy. Additionally, the Company is proposing an LVD tree-caused
5 outage review program to perform deeper causal analysis of tree-caused outages to provide
6 valuable insights and inform future line clearing strategy decisions.

7 **Q. Please describe the five-year cycle strategy and how it works.**

8 A. The five-year cycle strategy describes clearing one-fifth of the Company's LVD line miles
9 annually in steady-state cycle maintenance while maintaining the standard that all LVD
10 circuits have been fully cleared within a five-year period. The Company's proposal
11 includes a ramp-up strategy to eliminate all backlog miles (circuits that have not been fully
12 cleared within five years) by the end of the 2030-2031 test period. During this ramp-up
13 period, the Company proposes to utilize its forestry workplan selection tool to inform the
14 sequencing of backlog reduction based on its optimization outputs for reliability and safety
15 risk.

16 After the ramp-up period, steady-state cycle maintenance begins in 2031. At that
17 time, the Company will reevaluate other tactics for continuous improvement in risk
18 management.

19 **Q. Is the Company making changes to its key tracking metrics for LVD line clearing?**

20 A. Yes. As noted, the Company's vision includes bringing all LVD circuits, regardless of
21 voltage class, to a state of having been fully cleared within a five-year period to establish
22 a consistent, full cycle. In its previous rate cases describing the seven-year effective cycle
23 strategy, the Company has tracked progress towards the cycle utilizing a total-miles metric

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1 that encompassed all LVD full circuit clearing miles, LVD subprogram clearing miles,
2 LVD spray miles, and LVD capital clearing miles. This metric was used to summarize the
3 effective cycle for a given year, as shown in Exhibit A-170 (SES-1), line 40. To support
4 its vision, the Company will now track LVD full circuit clearing miles as its main metric
5 towards attaining the five-year cycle line clearing strategy and track other miles (LVD
6 subprogram clearing miles, LVD spray miles, and LVD capital clearing miles) separately
7 and not as part of the standard cycle. This metric is shown in Exhibit A-170 (SES-1),
8 line 23. This ensures the entire LVD system is brought to a consistent state of clearing
9 with no circuits or sections of circuits left in backlog status.

10 **Q. If the LVD system is to be on a five-year cycle by the end of the 2030-2031 test period,**
11 **what will happen to non-full circuit clearing subprograms?**

12 A. As the LVD system grows nearer to being on a five-year cycle, the necessity of partial
13 circuit clearing subprograms for reliability intervention (repetitive outage zonal clearing,
14 CEMI clearing, first zone clearing, LCP zonal clearing) lessens. Starting in 2026 and
15 through the 2030-2031 test period, the Company will phase out these subprograms for
16 backlog circuits in favor of full circuit clearing for these circuits to bring them on-cycle.
17 After the 2030-2031 test period when the LVD system is projected to be fully on-cycle, the
18 Company will only perform these activities on mid-cycle circuits if the need arises. The
19 Company finds that mid-cycle clearing is a common practice among utilities it conducts
20 benchmarking with.¹

¹ Specifically, Alliant Energy, Ameren Missouri, American Electric Power perform mid-cycle clearing.

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1 **Q. How will the Company address the backlog of circuits not cleared in many years?**

2 A. The Company's proposal to execute a five-year cycle strategy by the end of the 2030-2031
3 test period is made possible by preventing any on-cycle circuit from exceeding its cycle
4 and becoming a backlog circuit starting this test period. In practice, this means any LVD
5 circuit that reaches five years since it was last fully cleared, therefore reaching its cycle
6 length, is automatically included in the annual workplan for the year to be kept on-cycle.
7 As outlined in Figure 4, remaining miles for the workplan will be backlog miles, addressed
8 throughout the ramp-up strategy timeframe of this test period (Year 1) through the 2030-
9 2031 test period (Year 5).

FIGURE 4
PLAN FOR LVD BACKLOG MILES ELIMINATION
FULL CIRCUIT CLEARING MILES

Vision Year	Plan Miles	On Cycle Miles	Backlog Miles	Backlog Miles Remaining
Year 1	9,019	5,279	3,740	26,684
Year 2	10,885	6,338	4,547	22,138
Year 3	12,814	6,365	6,449	15,689
Year 4	13,588	6,042	7,546	8,143
Year 5	14,837	6,694	8,143	0

10 **Q. Why is the Company deviating from its previous seven-year effective cycle strategy?**

11 A. In its final report, Liberty recommended the Company achieve a four-or-five-year line
12 clearing cycle for LVD circuits by year-end 2028. While the Company has always
13 acknowledged the reliability benefits of shorter cycles (i.e., a reduced cycle results in lower
14 tree-caused outage rates on the LVD system), it has sought to balance reliability benefits
15 with costs to maintain the cycle. In previous rate case analysis, a seven-year effective cycle
16 was outlined as the most cost-beneficial approach for customers. Since that analysis took

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1 place, additional data analysis and information, including Liberty's recommendation and
2 report, has become available for consideration. The Company has carefully evaluated
3 projected costs and benefits of a shorter line clearing cycle for its LVD circuits and has
4 determined that a five-year line clearing cycle is the right approach to significantly improve
5 electric reliability while responsibly managing customer bill impacts.

6 **Q. Why is the Company's vision timeline to achieve the cycle longer than Liberty's**
7 **recommended timeline?**

8 A. While the Company is proposing a line clearing cycle that aligns with Liberty's
9 recommendation, the aggressive timeline of achieving the shorter cycle by year-end 2028
10 is not operationally feasible due to rate case timelines and resource acquisition challenges
11 that would result from such a short timeline (e.g., a full ramp-up and execution from mid-
12 2026 through year-end 2028). These resource acquisition challenges could also lead to
13 higher costs if the Company is required to rely on additional out-of-state crews, and these
14 higher costs also caution against a too-aggressive timeline. The Company's proposal to
15 achieve the reduced line clearing cycle reflects an operationally feasible timeline that is
16 just two to three years longer than Liberty's recommendation: by the end of the 2030-2031
17 test period.

18 **Q. Has the Company performed a formal optimization analysis of line clearing cycles**
19 **that accounts for customer costs of outages, the costs of service restoration, and the**
20 **costs of line clearing, including an evaluation of shorter clearing cycles?**

21 A. Yes. To comply with the Order for MPSC Case No. U-21389, the Company filed its formal
22 optimization analysis of line clearing cycles on September 3, 2024, in Case No. U-20697
23 (the "Analysis"). The Analysis is included in Exhibit A-176 (SES-7).

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1 **Q. What was the conclusion of the Analysis?**

2 A. The conclusion of the Analysis was an optimal cycle length between six and seven years,
3 prioritizing and focusing on residential customers. A four-year cycle length was first
4 identified as an optimal cycle when considering combined costs across all customer types
5 (residential and non-residential). The Company took the analysis a step further,
6 considering how line clearing and service restoration costs would be allocated to each
7 customer type. Residential customers bear the majority of the line clearing and service
8 restoration costs through rates as they make up the majority of the electric customers served
9 (about 88% of total). Upon isolating cost impacts on residential customers, and utilizing
10 then-current data, the Company's refined analysis found that a longer cycle length between
11 six and seven years was the optimal point for residential customers minimizing total costs.

12 **Q. Why isn't the Company proposing a cycle length matching the conclusion of the**
13 **Analysis for residential customers?**

14 A. The Company acknowledges Staff's concerns regarding the approach taken with the
15 Analysis. Among these, Staff comments that the Analysis uses the Interruption Cost
16 Estimate ("ICE") calculator and that these costs are low.² While the Company utilized the
17 data from the ICE calculator as it is the best available data of its kind, it acknowledges that
18 a higher residential customer cost of outages would drive the Analysis conclusion towards
19 a shorter optimal cycle for residential customers. The Company is adjusting its proposed
20 line clearing cycle length to accommodate Staff's concern, among other reasons. The
21 shorter cycle length also aligns with Liberty's recommendation, which is influenced by

² Michigan Public Service Commission Staff Reply Comments on the Final Report Utility Distribution Audit of Consumers Energy, January 17, 2025, pages 2-3

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1 benchmarking of other utilities, and would result in lower tree-caused outage rates on the
2 LVD system to provide customers with better reliability.

3 **Q. Has the Company analyzed the feasibility of more aggressive line clearing in**
4 **everything outside of the first zone?**

5 A Yes. To comply with the Order for MPSC Case No. U-21389, the Company has analyzed
6 the feasibility of more aggressive line clearing, defined as canopy removal, in everything
7 outside of the first zone and alternate options in Case No. U-21585.

8 **Q. For the Company's vision, what does more aggressive line clearing entail?**

9 A. More aggressive line clearing describes the practice of canopy removal, which is the
10 removal of all branches above primary wires. In comparison, the Company's general line
11 clearing specification for LVD primary has allowed some canopy to remain: healthy,
12 non-weak-wooded tree species canopy is cleared to 10-15 feet from the conductors, and
13 certain weak-wooded tree species canopy clearance is increased to 20 feet from the
14 conductors. The practice of canopy removal targets all branches above primary wires,
15 regardless of clearance distance, tree species, or health of limb.

16 **Q. Has the Company previously performed canopy removal on its LVD system?**

17 A. Yes. In 2022, the Company performed a small canopy removal study on approximately
18 42 miles of three phase primary which resulted in an observed average contractor cost
19 increase of 35% per mile cleared. Figures 5 and 6 show examples of canopy removal on
20 an urban and rural section of circuit respectively, pre- and post-clearing in 2022.

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FIGURE 5
CANOPY REMOVAL ON AN URBAN SECTION OF CIRCUIT, 2022



FIGURE 6
CANOPY REMOVAL ON A RURAL SECTION OF CIRCUIT, 2022



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1 **Q. Where is the Company proposing to remove canopy on its LVD system?**

2 A. The Company is proposing canopy removal on 10% or roughly 5,500 miles of overhead
3 primary, targeting the three phase portions of circuits that have the highest consequence of
4 failure due to serving the most downstream and/or critical customers. Decreasing the risk
5 of tree-caused outages along this targeted three phase primary increases the availability and
6 enablement of manual and automatic switching capabilities, reducing the impact of outages
7 that may occur regardless of cause.

8 **Q. Does this scope of canopy removal match an option presented in Case No. U-21585's**
9 **feasibility of more aggressive line clearing?**

10 A. No, this proposal does not directly match an option presented in Case No. U-21585, where
11 zones and number of phases were used to differentiate between options. The Company is
12 proposing that zone number alone not be the determining factor for canopy removal, but
13 the consequence of failure of the section of line in question, which will inherently include
14 the first and some second zones, but may extend past the second zone depending on the
15 zone attributes (e.g., number of customers served downstream, and/or if the conductor is
16 within the path of substation-to-substation connection to enable switching opportunities).

17 **Q. Why is the Company proposing to remove canopy on targeted LVD three phase lines?**

18 A. Upon evaluation of the feasibility of more aggressive line clearing on its LVD system, the
19 Company has integrated this tactic into its vision, scoped to the sections of line that are
20 projected to provide the greatest impact to overall customer reliability for the incremental
21 expense. It is not uncommon for electric utilities to have more aggressive clearing
22 specifications in early zones versus later zones; inherently, more customers are served by
23 early zones and by fewer zone miles, which increases overall customer benefit of more

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aggressive line clearing in these zones. As outlined in Case No. U-21585, 100% of customers fed by LVD lines are served within and downstream of first zones, which comprise about 6% of total LVD miles.

Q. How will the Company measure the reliability impact of the proposed targeted canopy removal?

A. To measure the reliability impact of the proposed targeted canopy removal, the Company plans to compare the zones that had canopy removal (i.e., “treatment population”) to zones or circuits that did not have canopy removal (i.e., “control population”). This comparison is intended to isolate and measure the impact of the treatment (i.e., canopy removal) effect on reliability. The Company is considering including this analysis in Case No. U-20697’s Line Clearing Program Annual Report, which details the progress of the line clearing program and the performance of LVD circuits post-clearing. While the Company is proposing to begin executing on its canopy removal strategy in this test period, it is crucial that the data size of the treatment population and amount of time post-treatment are of a significant size to ensure conclusions drawn from an analysis are statistically significant; therefore, measurement of the reliability impact of the proposed targeted canopy removal would appear at the earliest in the 2028 Line Clearing Program Annual Report, analyzing 2027 reliability performance. This will allow the treatment population time to begin collecting reliability data.

Q. Please describe the tree-caused outage review program and how it works.

A. The purpose of the tree-caused outage review program is to gather data on a subset of LVD tree-caused outages and determine top causal contributors, establish and monitor trends, and inform future line clearing strategy decisions. Data collection is to occur by outage

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1 investigators through a combination of: (i) field visits to the site where the tree-related fault
2 occurred; (ii) conversations with field employees that responded to the outage; and
3 (iii) conversations with in-office resources that were involved with the outage (i.e.,
4 dispatcher). The Company plans on utilizing contracted resources with a background in
5 forestry and an understanding of tree species and failure modes to perform the outage
6 investigator function.

7 **Q. What tree-caused outages will be targeted for the outage review program?**

8 A. The Company is proposing an outage review trigger upon meeting the following criteria:
9 (i) non-MED; (ii) circuit lockout and/or primary outage; (iii) cause code of Trees or Trees
10 - Outside ROW; and (iv) greater than or equal to 500 customers impacted. For the last five
11 years, there have been about 250 outages on average that meet these criteria annually.

12 **Q. What line clearing tactics are the Company proposing for wildfire mitigation?**

13 A. In Case No. U-21585, the Company proposed to implement a five-year line clearing cycle
14 in elevated wildfire risk areas better to manage growth and limit potential vegetation to
15 conductor contact. The incremental expense for this was outlined in Company witness
16 Michael P. Kelly's Exhibit A-114 (MPK-22) in Case No. U-21585. Because the Company
17 is proposing a shorter five-year cycle for the entirety of its LVD system, the line clearing
18 expense in the elevated wildfire risk areas is now included in the overall Line Clearing
19 Program costs outlined in Exhibit A-170 (SES-1) and are no longer an incremental
20 expense.

21 While the Company outlines a timeline to achieve the vision by the end of the 2030-
22 2031 test period for all LVD circuits, it is proposing a more aggressive timeline in wildfire

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1 risk areas, namely, achieving the five-year cycle for circuits in the relatively high wildfire
2 risk area by year-end 2026 and relatively moderate wildfire risk area by year-end 2028.

3 **Q. What does the Company have planned for future enhancements to technology?**

4 A. The Company continues to evaluate new forestry workflow management processes and
5 technology enhancements. The Company's Forestry Operations Department is utilizing
6 Microsoft Access and Excel for system-wide program workflow management, contract
7 invoicing, and data storage. The Company is exploring an opportunity to upgrade to IT-
8 supported systems that integrate cloud technology, support updated data storage and
9 management infrastructure, have an improved user interface, integrate with other
10 tools/data, enable automation opportunities, provide expansion in security and control
11 capability, and allow for near real-time data reporting/visual management capabilities.

12 **Q. Is the Company pursuing advanced remote sensing to improve its forestry model?**

13 A. No, the Company is not pursuing system-wide advanced remote sensing to improve its
14 forestry model at this time. The Company is conducting a small pilot to capture Light
15 Detection and Ranging ("LiDAR") imagery, which was proposed in Case No. U-21585.
16 The purpose of this pilot is to inform and support the execution strategy of LVD line
17 clearing tactics in relatively high-risk wildfire areas. The Company is proposing to
18 continue this pilot annually to evaluate the benefits of utilizing this data on a small scale
19 first, before re-evaluating expanding this LiDAR pilot to a larger scope, up to and including
20 LVD system-wide utilization. This supports the Company's phased approach to imagery
21 analysis utilization: short-to-medium-term utilization of zero-to-low-cost satellite imagery
22 analysis and focused LiDAR pilot projects during the ramp-up to a five-year cycle, and

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1 long-term re-evaluation of larger scope LiDAR acquisition and utilization to further reduce
2 outages once the LVD system is fully on the five-year cycle.

3 **Q. Is the Company planning on using drone technology for its Line Clearing Program?**

4 A. Yes, the Company is exploring the use of drone technology to research opportunities in
5 data collection and analysis through partnership with its Forestry Operations, Unmanned
6 Aircraft Systems, and Geographic Information System departments. Drones are being used
7 by several utilities as a means of collecting various types of high-resolution data in targeted
8 areas. The Company is researching multiple sensor packages (e.g., multispectral, infra-red,
9 and LiDAR) for targeted inspections and documentation of vegetation along the electric
10 system. These technologies have the potential to enhance current practices by identifying
11 declining trees early, detecting the efficacy of herbicide applications, and quantifying tree
12 biomass volume within and along electric corridors.

13 **RELIABILITY BENEFITS OF THE LINE CLEARING PROGRAM**

14 **Q. Why is line clearing beneficial to the Company and its electric customers?**

15 A. Trees are the greatest cause of interruptions to electric service for customers on the LVD
16 system and a significant cause of outages or interruptions of electric service on the HVD
17 system. Figure 7 below shows the history of tree-caused interruptions affecting customers
18 from 2020 through 2024 including: (i) the number of outage incidents; (ii) customers
19 interrupted; and (iii) customer minutes of outage. The Company's Line Clearing Program
20 is designed to minimize these occurrences, improve reliable service to its customers, and
21 decrease reactive maintenance and capital expense associated with interruptions during
22 weather events. The Company's proposed five-year cycle strategy will yield significant
23 improvement to customers' electric service.

FIGURE 7
TREE-CAUSED RELIABILITY METRICS 2020 THROUGH 2024
ALL VOLTAGES INCLUDING MEDS (Excluding ITC incidents)

Description	2020	2021	2022	2023	2024
Incidents	18,599	24,163	17,078	18,298	20,326
Customers Interrupted	930,974	1,314,220	919,156	1,037,857	1,084,052
Customer Minutes (M)	494.290	1011.992	444.309	899.756	548.880

The Company's Line Clearing Program also provides benefits that are not easily quantified, such as improved habitat for many plants and animals (including threatened and endangered species) and decreased risk of wildfires from tree contact with conductors. Enhancing the Company's Line Clearing Program will result in less aesthetic impact to customer properties (as clearing will occur more frequently, establishing expectations with property owners) and will improve public safety.

Q. What benefits will customers realize through the requested spending level in the HVD line clearing subprogram?

A. The Company's four-year cycle for HVD line clearing is effectively managing the number of HVD line outage incidents from trees within the right-of-way. The HVD system is the foundation and source for the LVD system. Outages on the HVD system can have broad impacts and can affect large numbers of customers. In the years 2020 through 2024, the average customer impact of a non-MED tree outage incident on an LVD circuit was 45 customers and the average customer impact of a non-MED tree outage incident on an HVD line was 471 customers. HVD line clearing benefits customers by mitigating the amount of these high customer impact outages. Additionally, outages on the HVD lines system often take longer to repair and therefore have higher customer minute impacts.

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Maintaining a four-year HVD line clearing cycle is necessary to minimize the impact of HVD tree outages to the LVD system and customers.

Q. What benefits will customers realize through the requested spending level in the LVD line clearing subprogram?

A. The Company's vision outlines a more aggressive plan of increasing the number of miles cleared each year, resulting in a decrease in the number of tree-related outages to the LVD system. Exhibit A-171 (SES-2) illustrates the projected reduction in non-MED and MED tree-caused primary outage incidents, System Average Interruption Frequency Duration ("SAIFI"), and System Average Interruption Duration Index ("SAIDI"). Figures 8, 9, and 10 below show the reliability projections by metric for 2025 through 2030 for the proposed line clearing spending levels to achieve the Company's vision. The values at the top of each bar represent overall reliability projections including MED.

FIGURE 8
PROJECTED 2025-2030 LVD TREE-CAUSED
PRIMARY OUTAGE INCIDENTS

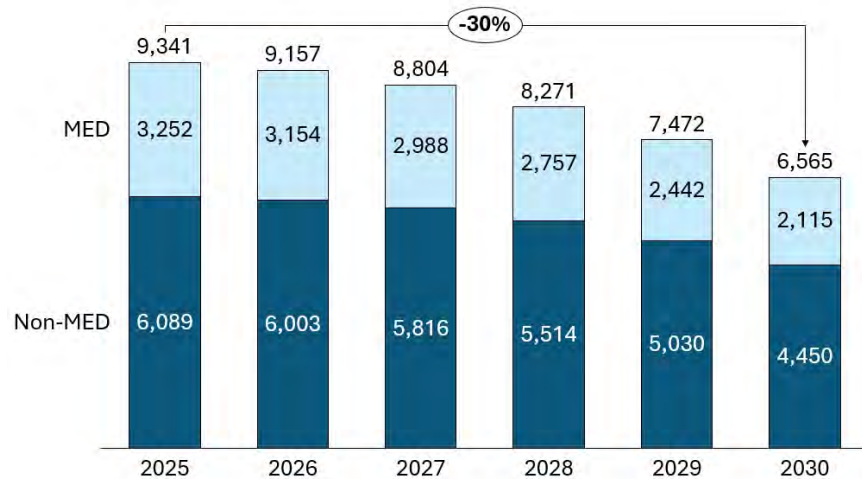


FIGURE 9
PROJECTED 2025-2030 LVD TREE-CAUSED
SAIFI DUE TO PRIMARY OUTAGES

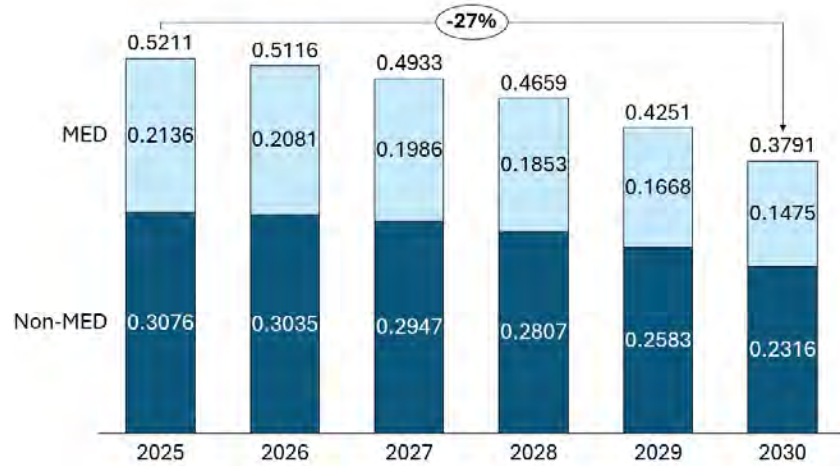


FIGURE 10
PROJECTED 2025-2030 LVD TREE-CAUSED
SAIDI DUE TO PRIMARY OUTAGES



1 The Company's requested LVD line clearing spending level also supports the
2 subprograms described earlier in my testimony that address sections of circuits from
3 protective device to protective device, or protective device to end of circuit, that are
4 experiencing multiple tree-related outage incidents.

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1 **Q. What is the source of these reliability projections?**

2 A. The reliability projections in Exhibit A-171 (SES-2) are from the Company's reliability
3 model as described in Company witness Kelly's testimony, page 28, lines 1 through 10.
4 The reliability projections in Exhibit A-171 (SES-2) also factor in the Company's proposed
5 canopy removal on targeted three phase lines.

6 **Q. When will reliability benefits of the new cycle be fully realized?**

7 A. The Company projects that reliability benefits of the new cycle will be fully realized
8 through the second clearing cycle, or roughly by 2036. Liberty's President John Antonuk
9 discussed this phenomenon in his presentation at the Commission's September 26, 2024,
10 meeting,³ attributing more significant reliability improvement across the second cycle due
11 to a lack of completeness of line clearing work within the first cycle. While the Company
12 agrees that it would likely not see full reliability benefits of the new cycle until the second
13 clearing cycle, it does not agree that this is because its line-clearing work is incomplete.
14 Rather, the partially delayed benefit Mr. Antonuk described may be driven by the lack of
15 "wind firmness" of the surrounding healthy trees remaining after line clearing is performed
16 that were not targeted for removal. My Land Plan, provided by the American Forest
17 Foundation, describes wind firmness as the ability of trees to sway with strong winds
18 without breaking or toppling, and to return to their normal position once a wind gust or
19 storm passes.⁴ While the Company has found little to no formal research referencing this
20 concept as it relates to utility line clearing specifically, as most of the research concentrates

³ Commission Meeting, YOUTUBE (Sept 26, 2024) at ~50:30, <https://www.youtube.com/watch?v=QWq5syDj94w>
("For vegetation . . . the first cycle, when you advance, uh, when you shorten the cycle for vegetation, it's usually, the
work is not as complete or as thorough as the second cycle, so you really, you really should start to see more, much
more significant improvement across the second cycle. . . .")

⁴ American Forest Foundation, *How Windstorms Affect Your Forest*, My Land Plan,
<https://mylandplan.org/content/how-windstorms-affect-your-forest>.

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on general forest management practices, the same principle applies to trees along circuits recently cleared that had not been cleared for many years prior. When many years pass between clearing, trees have more time to grow, and line clearing will result in more significant biomass removal. Trees adapt to the patterns of physical stimulation they experience as they grow,⁵ and if trees have experienced a different wind pattern due to the density of surrounding trees, now removed due to line clearing, they must adapt or risk failure. The Company plans to utilize the proposed tree-caused outage review program to gain deeper insights of outage causes to determine if this phenomenon is causing a significant impact to outages post-clearing.

Q. Has the Company considered the benefits of shifting to a four-year fixed line clearing cycle based on the findings of the Analysis as the Commission directed in its recent Order in Case No. U-21585?

A. Yes, the Company has considered the costs and benefits of shifting to a four-year fixed line clearing cycle, and it asserts that the prudent next step in the evolution of its Line Clearing Program is the outlined five-year line clearing cycle, continuing to prioritize residential customer cost-benefit. The Company has compared the estimated costs and projected benefits of achieving a four- and five-year line clearing cycle in the same ramp-up strategy period of this test period through the 2030-2031 test period. The Company estimates that achieving a four-year cycle in the same timeframe could raise expenses nearly 15% overall, with some years as high as 23%. In its comparison, the Company assumed a 0% change in expenses in this test period as it has projected the most aggressive crew resourcing plan

⁵ Amanda Bunce, *Wind and Trees 101: To Touch a Tree, Stormwise Forest Management*, University of Connecticut College of Agriculture, Health, and Natural Resources & School of Engineering (May 8, 2017), <https://stormwise.uconn.edu/2017/05/08/wind-and-trees-101-to-touch-a-tree/>

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1 it believes it can achieve in the first year. The Company estimates that this increased
2 spending could result in only 3% additional reliability benefit across multiple metric types
3 due to diminishing returns.

4 It is important to note that, to increase line clearing miles in this ramp-up timeframe,
5 the majority of the incremental expense is due to increasing out-of-state tree crewing. This
6 resource is a more expensive resource than local tree crewing. Once the Company is on a
7 five-year cycle, it projects the need for out-of-state tree crewing is eliminated due to the
8 efficiencies a shorter cycle brings. The incremental cost of moving from a five-year cycle
9 to a four-year cycle may be prudent in the future; however, the Company's LVD system is
10 not currently on a five-year cycle, and significant out-of-state resources would be necessary
11 to bring the system to an even shorter four-year cycle at this time. Once the five-year cycle
12 is attained, the Company will reevaluate other tactics for continuous improvement in risk
13 management, including cycle considerations.

14 **Q. What reliability benefit is attributed to canopy removal?**

15 A. The Company estimates it would see a 4% reduction in primary tree-caused incidents from
16 canopy removal on targeted three phase lines.

17 **Q. How was the reliability benefit of canopy removal calculated?**

18 A. The Company utilized benchmarking data found in Exhibit A-177 (SES-8)⁶ indicating a
19 6% outage reduction opportunity through canopy removal. Because the Company is
20 proposing to remove canopy along a portion of its LVD primary, and it estimates this
21 portion of LVD primary impacts 2/3rds of customers impacted by tree-caused outages, it

⁶ Page 27, Figure 6-4 (Permission to use this study was obtained from its authors).

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1 applied this 6% reduction across roughly 2/3rds of customers interrupted by tree-caused
2 events. This results in a calculation of a 4% tree-caused reliability improvement overall.

3 **EXPENSE REQUIREMENTS FOR THE LINE CLEARING PROGRAM VISION**

4 **Q. What are the projected expense requirements to maintain the HVD system on its**
5 **four-year cycle?**

6 **A.** The projected expense requirements to maintain the HVD system on its four-year cycle are
7 displayed in Figure 11 below:

FIGURE 11
HVD LINE CLEARING SCHEDULE

Calendar Year	Data Type	O&M Maintenance Clearing Miles	Capital Clearing Miles	O&M Expense (\$M)	Capital Contractor Costs (\$M)	Local Crews
2020	Actual	1,116	46	\$9.17	\$1.18	41
2021	Actual	1,178	89	\$10.74	\$1.80	42
2022	Actual	1,106	70	\$10.99	\$0.80	38
2023	Actual	1,153	29	\$11.30	\$0.53	38
2024	Actual	1,203	78	\$10.73	\$2.43	38
2025	Projected	1,104	129	\$12.20	\$4.12	38
2026	Projected	1,177	138	\$11.99	\$4.49	38
2027	Projected	1,162	138	\$11.55	\$4.58	38
2028	Projected	1,120	138	\$11.20	\$4.66	38
2029	Projected	1,167	138	\$11.40	\$4.75	38
2030	Projected	1,177	138	\$11.60	\$4.83	38

8 **Q. What are the projected expense requirements for the LVD system ramp-up to achieve**
9 **the Line Clearing Program vision of a five-year clearing cycle and more aggressive**
10 **line clearing on targeted three phase lines?**

11 **A.** The projected expense requirements for the ramp-up to achieve the LVD Line Clearing
12 Program vision are displayed in Figure 12 below:

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FIGURE 12
LVD LINE CLEARING RAMP-UP SCHEDULE

Calendar Year	Data Type	O&M Full-Circuit Clearing Miles	O&M Subprogram Clearing Miles	O&M Subprogram Spray Miles	Capital Clearing Miles	O&M Expense (\$M)	Capital Contractor Costs (\$M)	Local Crews	Out-of-State Crews	Total Crews
2020	Actual	3,679	294	238	258	\$46.10	\$5.67	220	0	220
2021	Actual	4,647	238	395	252	\$75.83	\$6.07	299	0	299
2022	Actual	5,653	247	488	221	\$91.02	\$6.71	334	0	334
2023	Actual	5,758	244	443	168	\$97.79	\$5.59	348	0	348
2024	Actual	5,400	244	421	258	\$99.49	\$9.69	347	0	347
2025	Projected	6,108	244	413	325	\$113.20	\$14.01	364	0	364
2026	Projected	7,891	199	405	325	\$152.97	\$14.29	403	53	456
2027	Projected	10,885	149	454	325	\$201.75	\$14.57	420	120	540
2028	Projected	12,814	137	501	325	\$226.28	\$14.87	420	158	578
2029	Projected	13,588	75	491	325	\$230.43	\$15.16	420	158	578
2030	Projected	14,837	75	508	325	\$236.81	\$15.47	420	158	578

Q. What expense is the Company projecting to maintain the five-year clearing cycle after it is achieved?

A. The Company's current projection for the annual expense to maintain the five-year cycle after it is achieved in the 2030-2031 test period is \$180.359 million (\$168.525 million of which are LVD expenses) and subject to inflation in years after. The Company is referring to this measure as the baseline expense.

Q. What baseline expense requirement is the Company projecting for the test period?

A. The Company projects a baseline expense requirement of \$164.446 million (\$152.606 million of which are LVD expenses) for the test period.

Q. How were the baseline expense requirement for the test period and the baseline expense for the years leading up to achieving the five-year cycle calculated?

A. The baseline expense requirement for the test period of \$164.446 million was calculated utilizing the Company's current projection for the annual expense to maintain the five-year cycle after it is achieved in the 2030-2031 test period, adjusted to test period dollars.

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Figure 13 below shows the outcome of this calculation methodology for the calendar years leading up to achieving the five-year cycle.

FIGURE 13
PROJECTED LINE CLEARING PROGRAM EXPENSES
AND BASELINE EXPENSE REQUIREMENTS

12-Month Timeframe	Total O&M Expense (\$M)	Baseline O&M Expense (\$M)
2026 Calendar	\$164.953	\$163.357
2027 Calendar	\$213.300	\$166.624
2028 Calendar	\$237.485	\$169.956
2029 Calendar	\$241.826	\$173.356
2030 Calendar	\$248.414	\$176.823
U-21870 Test Period	\$186.684	\$164.446
Post-Vision	\$180.359	\$180.359

Q. Why is this baseline expense requirement different than the five-year cycle estimation in the Analysis?

A. In the Analysis, the Company estimated an annual expense to maintain the LVD system on a five-year cycle in a steady state (once the cycle had already been achieved and there are no backlog miles that have gone longer than the cycle length between clearing) of \$134.441 million.⁷ This value is different than the LVD baseline expense requirement in Exhibit A-170 (SES-1), column (q), line 12, of \$152.606 million. There are refined and updated assumptions that have impacted this projection, including overall crew resourcing, and the consideration of overtime for both local and out-of-state tree crews. Another notable difference in these values is that the Analysis utilized the timeframe of one year using costs inflated to 2024, whereas the baseline expense requirement in Exhibit A-170 (SES-1) is adjusted to the test period for this case.

⁷ The Analysis, Attachment 3, column (g), line 42

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1 **Q. What level of spending is the Company proposing for the 2026 calendar year and the**
2 **test period for its Line Clearing Program?**

3 A. As discussed below in greater detail under each subprogram of my direct testimony, the
4 Company is proposing to spend \$164.953 million for line clearing in the 2026 calendar
5 year and \$186.684 million for line clearing in the test period, as shown in Figure 14 below
6 and in Exhibit A-170 (SES-1).

FIGURE 14
LINE CLEARING EXPENSES
2026 CALENDAR YEAR AND TEST PERIOD

Categories	2026 Calendar Total O&M Expenses	Test Period Total O&M Expenses
HVD Line Clearing	\$10,910,683	\$10,755,522
LVD Line Clearing	\$144,782,420	\$164,864,105
Line Clearing Admin	\$9,260,324	\$11,064,347
Total	\$164,953,427	\$186,683,974

7 **Q. What is the line item in Figure 14 titled Line Clearing Admin?**

8 A. Line Clearing Admin is the internal salaries and expenses of the Company's Forestry
9 Operations Department, which administers the contracts and oversees the performance of
10 the Company's line clearing contractors. It also includes the contract foresters and work
11 planners utilized through a contract with ArborMetrics Solutions LLC that plan the work
12 and interact with customers. This amount for the 2026 calendar year is reflected in Exhibit
13 A-170 (SES-1), column (j), lines 30, 31, and 32.

14 **Q. What inflationary rates were used to determine the projections in Figure 14?**

15 A. The Company's internal labor expenses for Forestry Operations shown in Figure 14 and
16 Exhibit A-175 (SES-6) are a combination of current staffing, anticipated retirements,
17 replacement and new hiring, merit increases, and contracted planning resources. Please

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refer to the direct testimony of Company witness Patrick D. Daly, page 14, lines 9-11, and page 15, lines 1-2, for details on the Company's projected merit and inflationary rates, which were utilized for Line Clearing Admin expense projections. All contractor rates are contractually limited through mid-2029 to an annual adjustment of a minimum of 0.0% per year up to a maximum of 2.5% per year based on the Producers Price Indices WPUFD4 and WPU443. Figure 15 below shows the 2024 results for Producers Price Indices WPUFD4 and WPU443 published January 14, 2025.

FIGURE 15
PPI COMMODITY DATA FOR ANNUAL CONTRACTOR RATE ADJUSTMENT

PPI Commodity Data

12-Month Percent Change

Series Id: WPUFD4

Not Seasonally Adjusted

Series Title: PPI Commodity data for Final demand, not seasonally adjusted

Group: Final demand

Item: Final demand

Base Date: 200911

Years: 2019 to 2024

Year	Percent Change												Annual
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2019	1.9	1.9	2.0	2.4	2.1	1.6	1.6	1.9	1.5	1.0	1.0	1.4	1.7
2020	2.0	1.1	0.3	-1.5	-1.1	-0.7	-0.3	-0.3	0.3	0.6	0.8	0.8	0.2
2021	1.6	3.0	4.1	6.5	7.0	7.6	8.0	8.7	8.8	8.9	9.9	10.0	7.0
2022	10.1	10.4	11.7	11.2	11.1	11.2	9.7	8.7	8.5	8.2	7.4	6.4	9.5
2023	5.7	4.7	2.7	2.3	1.1	0.3	1.1	1.9	1.8	1.1	0.8	1.1	2.0
2024	1.0	1.6	2.0	2.3	2.5	2.9	2.4	2.1	2.1	2.6	3.0	3.3	2.3

PPI Commodity Data

12-Month Percent Change

Series Id: WPU443

Not Seasonally Adjusted

Series Title: PPI Commodity data for Rental and leasing of goods (partial)-Construction, mining, and forestry machinery

Group: Rental and leasing of goods (partial)

Item: Construction, mining, and forestry machinery and equipment rental and leasing

Base Date: 200903

Years: 2019 to 2024

Year	Percent Change												Annual
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2019	-0.1	-1.4	-0.9	0.4	1.8	1.9	0.8	0.8	0.1	-0.5	-1.1	-1.3	0.0
2020	-1.6	-1.7	-0.1	-1.1	-1.9	-2.4	-3.8	-3.3	-4.4	-4.6	-4.3	-4.6	-2.8
2021	-4.8	-4.6	-4.0	-2.6	-2.5	-2.4	-0.4	-0.4	1.0	1.4	2.0	2.1	-1.3
2022	1.9	2.5	1.4	1.6	3.3	4.9	4.4	7.5	7.3	7.1	6.5	8.1	4.7
2023	9.8	9.2	9.2	9.3	7.7	5.8	6.3	2.2	2.5	2.7	2.5	1.2	5.6
2024	-0.1	-1.0	0.5	0.1	-0.8	0.0	-0.4	1.0	0.8	0.4	0.6	0.0	0.1

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1 **Q. What is the Company's projected 2026 calendar year and test year spending level, for**
2 **which it is requesting cost recovery, in the HVD line clearing subprogram?**

3 A. The Company is projecting HVD line clearing expenses of \$11.987 million in the 2026
4 calendar year and \$11.840 million in the test period, as shown in Figure 16 below and in
5 Exhibit A-170 (SES-1).

6 **Q. How would these projected expenses be allocated among the categories of work**
7 **described above?**

8 A. The Company is projecting expenses in the 2026 calendar year and test period for each
9 category as identified in Figure 16 below:

FIGURE 16
HVD LINE CLEARING EXPENSES
2026 CALENDAR YEAR AND TEST PERIOD

Categories	2026 Calendar		Test Period	
	Expenses	Line Miles	Expenses	Line Miles
Maintenance clearing	\$4,886,488	587	\$4,870,358	584
Brush control	\$5,869,195	586	\$5,730,163	584
Demand	\$60,000	4	\$60,000	4
Noxious weed control	\$95,000	n/a	\$95,000	n/a
Line Clearing Admin	\$1,076,037	n/a	\$1,084,138	n/a
Total	\$11,986,720	1,177	\$11,839,660	1,172

10 **Q. What spending level for the HVD line clearing subprogram was approved in the**
11 **Company's last electric rate case order?**

12 A. In MPSC Case No. U-21585, the Company requested a line clearing spending level of
13 \$125.086 million. Company witness Pamela L. Bolden testified in that case that the HVD
14 allocation would be \$12.294 million for the 2025 calendar year and \$11.972 million for the
15 2026 calendar year, which equated to \$12.240 million in the 2025 test period (March 2025
16 through February 2026).

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1 **Q. Does the Company request to recover the entirety of its HVD line clearing O&M**
2 **spending in the test period through base rates?**

3 A. Yes, it does.

4 **Q. What is the Company's projected 2026 calendar year and test year spending level, for**
5 **which it is requesting cost recovery, in the LVD line clearing subprogram?**

6 A. The Company is projecting LVD line clearing expenses of \$152.967 million in the 2026
7 calendar year and \$174.844 million in the test period, as shown in Figure 17 below, and in
8 Exhibit A-170 (SES-1).

9 **Q. How would these projected expenses be allocated among the categories of work**
10 **described above?**

11 A. The Company is projecting expenses in the 2026 calendar year and test period for each
12 category as identified in Figure 17 below:

FIGURE 17
LVD LINE CLEARING EXPENSES
2026 CALENDAR YEAR AND TEST PERIOD

Categories	2026 Calendar		Test Period	
	Expenses	Line Miles	Expenses	Line Miles
Full Circuit Clearing	\$135,674,820	7,891	\$156,029,100	9,019
Repetitive Outage	\$1,057,600	40	\$1,005,067	36
CEMI Clearing	\$500,000	34	\$450,000	31
First Zone Clearing	\$1,000,000	55	\$883,333	50
LCP Zonal Clearing	\$800,000	27	\$729,938	24
Demand Work	\$2,250,000	44	\$2,100,000	40
Brush Control	\$3,500,000	405	\$3,666,667	422
Line Clearing Admin	\$8,184,287	n/a	\$9,980,209	n/a
Total	\$152,966,707	8,496	\$174,844,314	9,622

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1 **Q. What expense is associated with more aggressive line clearing on targeted three phase**
2 **lines?**

3 A. The expense associated with more aggressive line clearing on targeted three phase lines is
4 contained in the full circuit clearing category of work in the amount of \$4.172 million for
5 the 2026 calendar year spending level, which is eight months (8/12ths) of the test period
6 incremental expense, shown as Year 1 in Figure 18 below.

7 **Q. How was the expense associated with more aggressive line clearing on targeted three**
8 **phase lines calculated?**

9 A. The Company estimates that one-fifth of the targeted three phase lines, or about
10 1,100 miles, will have canopy removal each year through the five-year vision timeframe.
11 In its canopy removal study in 2022, the Company observed an average contractor cost
12 increase of 35% per mile cleared. This cost assumption was utilized across the
13 1,100 estimated annual miles considering the percentage of total hours worked by local
14 crews and out-of-state crews and an assumed split of on-cycle miles and backlog miles.
15 The vision miles and incremental expense for canopy removal on targeted three phase lines
16 is displayed in Figure 18 below:

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FIGURE 18
VISION MILES AND INCREMENTAL EXPENSE FOR CANOPY REMOVAL
ON TARGETED THREE PHASE PRIMARY

Vision Year	Cycle Miles	Backlog Miles	Total Miles	Incremental Cost per Mile	Incremental Canopy Removal Expense (\$M)
Year 1	550	550	1,100	\$5,689	\$6.258
Year 2	660	440	1,100	\$5,553	\$6.108
Year 3	770	330	1,100	\$5,320	\$5.852
Year 4	880	220	1,100	\$5,136	\$5.649
Year 5	990	110	1,100	\$4,909	\$5.399
Total	3,850	1,650	5,500	\$5,321	\$29.267

1 **Q. What spending level for the LVD line clearing subprogram was approved in the**
2 **Company's recent electric rate case orders?**

3 **A. The approved spending level for the LVD line clearing subprogram in the Company's**
4 **recent electric rate case orders is outlined in Figure 19 below:**

FIGURE 19
LVD LINE CLEARING AUTHORIZED SPEND

MPSC Case No.	Timeframe	LVD Authorized Spend (\$M)
U-20697	January 2021 - December 2021	\$71.430
U-20963	January 2022 - December 2022	\$81.089
U-21224	January 2023 - December 2023	\$87.966
U-21389	March 2024 - February 2025	\$106.608
U-21585	March 2025 - February 2026	\$113.168 ⁸

⁸ Includes wildfire risk mitigation expenditures.

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Q. Has the Company met its commitment to spending the authorized amounts for the Line Clearing Program in MPSC Case Nos. U-20697, U-20963, U-21224, U-21389, and U-21585?

A. Yes, the Company has met its commitment to spend the authorized amounts for the Line Clearing Program in MPSC Case Nos. U-20697, U-20963, U-21224, and U 21389. In the test period for Case No. U-21585 (March 2025 through February 2026), the Company plans to spend \$125.087 million for its Line Clearing Program and an additional \$0.321 million for wildfire risk mitigation line clearing as projected in Company witness Kelly's Exhibit A-114 (MPK-22) in Case No. U-21585 and the Commission's Order in that case dated March 21, 2025, page 93. Figure 20 below outlines each MPSC Case No. authorized spend and actual spend. Over this timeframe, the Company invested \$19.973 million in its Line Clearing Program above the authorized spend amount.

FIGURE 20
LINE CLEARING PROGRAM SPEND AUTHORIZED TO ACTUAL

MPSC Case No.	Timeframe	Authorized Spend (\$M)	Actual Spend (\$M)	Difference in Authorized Spend and Actual Spend (\$M)
U-20697	January 2021 - December 2021	\$84.000	\$86.567	\$2.567
U-20963	January 2022 - December 2022	\$93.959	\$102.003	\$8.044
U-21224	January 2023 - December 2023	\$100.030	\$109.093	\$9.063
U-21389	March 2024 - February 2025	\$118.890	\$119.189	\$0.299
U-21585	March 2025 - February 2026	\$125.408 ⁹	\$125.408 ¹⁰	\$0.000
Total	January 2021 - February 2026	\$522.287	\$542.260	\$19.973

⁹ Includes wildfire risk mitigation expenditures.

¹⁰ Projected spend.

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1 **Q. How did the Company project spending for the 2025 calendar year, the 2026 calendar**
2 **year, and the test period (May 1, 2026 through April 30, 2027)?**

3 A. The 2025 calendar year spending projection in the Company's 2024 Electric Rate Case No.
4 U-21585 totaled \$125.408 million for both LVD and HVD programs, including wildfire
5 risk mitigation expenditures. The Company sought an increase for the 2025 calendar year
6 based on the fifth year of the five-year spending plan presented in MPSC Case Nos.
7 U-20697, U-20963, U-21224, and U-21389 with adjustments in the HVD and LVD
8 subprogram totals from previous filings. For this case, projected test period spending was
9 derived from operational intelligence by Forestry Operation's Senior Manager, Manager
10 of Strategic Planning and Performance, and other staff members. Values presented in
11 Exhibit A-170 (SES-1) are the Forestry Operation team's projections, informed by
12 historical costs per mile cleared, current system work estimates, crew availability and work
13 schedules, and other factors to maintain clearing on the HVD system at current level and
14 to reduce the clearing cycle on LVD. As average monthly spending is not consistent during
15 a significant ramp-up period (i.e., crewing may sharply increase at any one time when
16 availability permits), the test period for this case (May 1, 2026 through April 30, 2027)
17 presented in Exhibit A-170 (SES-1) is not calculated using ratios of eight months (8/12th)
18 of the 2026 calendar year and four months (4/12th) of the 2027 calendar year, but instead
19 driven by the aforementioned operational intelligence (e.g., striking an appropriate rate of
20 crew ramp-up based on vendor availability, field planning resources, and supervision).

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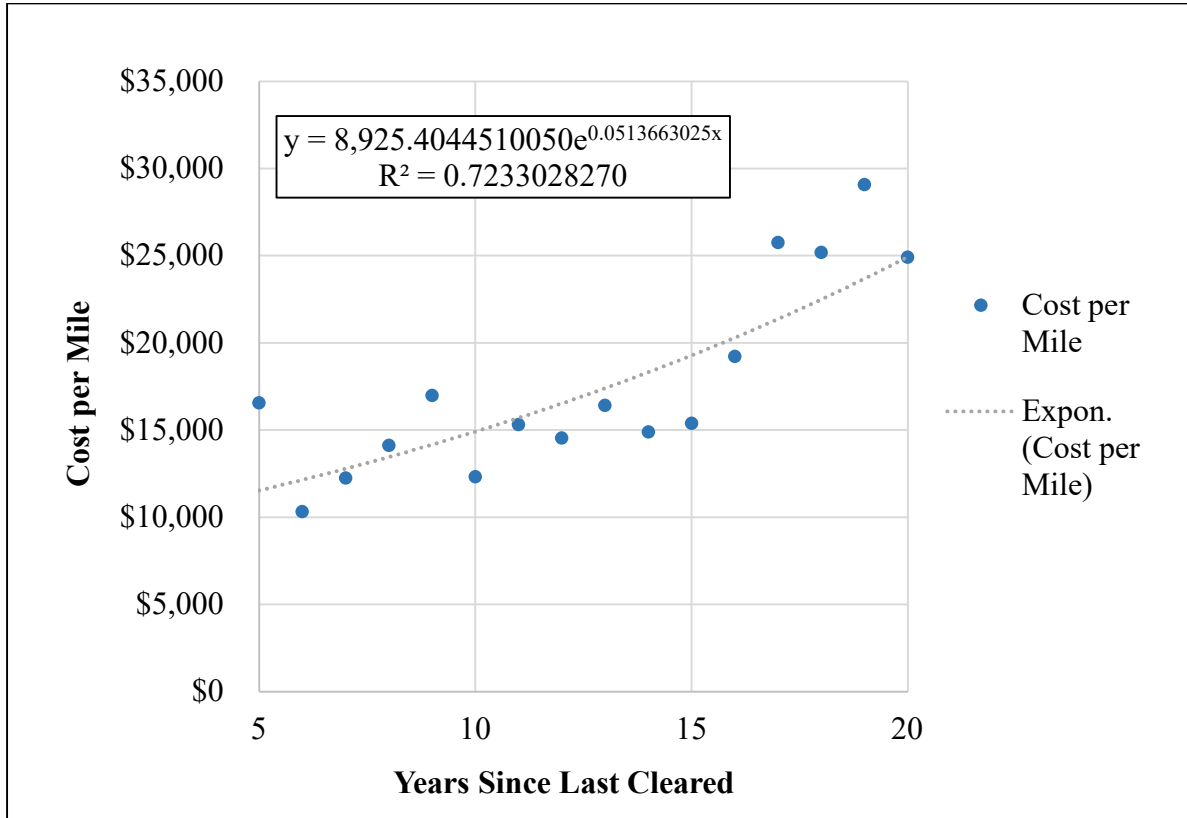
1 **Q. For the test year, what will happen to dollars remaining if the HVD workplan is**
2 **completed under budget?**

3 A. If the HVD workplan is completed under budget, any remaining dollars for the test year
4 will be allocated to the LVD system to support the Company's vision of attaining a
5 five-year cycle by the end of the 2030-2031 test period while still maintaining the HVD
6 system on its four-year cycle.

7 **Q. Does a shorter clearing cycle reduce the average cost per line mile to clear circuits?**

8 A. Yes, the Company's data supports that a shorter clearing cycle results in a lower average
9 cost per line mile to clear circuits. Longer clearing cycles result in more complex clearing
10 work and require the removal of more biomass to achieve clearance to conductors, as the
11 vegetation has had more time to grow between clearings. To inform its expense projections
12 for its vision, the Company considered lower costs per mile to maintain circuits on a shorter
13 cycle. Figure 21 below shows the relationship between clearing costs per mile and the
14 number of years between clearings utilizing the most recently available full circuit clearing
15 data from 2024 on circuits last cleared 5 to 20 years earlier. It is important to note that
16 there is more available data on longer durations between clearings as the Company has
17 been working to reduce the LVD backlog. Some data exists for shorter durations between
18 clearings to inform this trend and more will become available as the Company's vision
19 includes performing clearing on more cycle circuits starting in 2026, preventing cycle
20 circuits from becoming backlog circuits. This data will continue to be refined, and expense
21 projections updated accordingly.

FIGURE 21
2024 CONTRACTOR FULL CIRCUIT CLEARING COST PER LVD MILE BASED ON YEARS SINCE LAST CLEARED



Q. What are the historical unit costs for the Company's O&M clearing work in the LVD line clearing subprogram?

A. Unit costs over the last five years are provided in Figure 22 below:

FIGURE 22
LVD LINE CLEARING UNIT COSTS

Description	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024
O&M Cleared Miles	4,211	5,279	6,388	6,365	6,030
O&M Expense (\$M)	\$46.10	\$75.83	\$91.02	\$97.79	\$99.49
\$/line mile	\$10,948	\$14,364	\$14,248	\$15,364	\$16,499

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1 **Q. Please explain the increase in unit costs in recent years.**

2 A. Unit costs decreased significantly in 2020 due to coronavirus pandemic restrictions with
3 decreases in customer interactions with line clearing crews and forestry operations
4 personnel about the planned line clearing work. This permitted clearing operations to
5 proceed in an efficient manner without work stoppages or delays to address customer
6 concerns in the field. As predicted in MPSC Case No. U-20963, the unit cost returned to
7 “normal” levels in 2021 with additional increases as described below.

8 The greatest impact on unit costs for 2021 and 2022 was the ramp-up with many
9 new contractor employees and vendors new to the utility line clearing business. New
10 employees are less productive until their skill levels develop to optimal performance while
11 maintaining safety protocols. Secondly, the addition of new Michigan-based vendors, all
12 of which are smaller scale operations compared to the large nationwide utility line clearing
13 contractors, increased unit costs as their business cost structures are much different than
14 the nationwide vendors. In time, as these Michigan-based vendors grow, their cost
15 structures will align more closely to the nationwide vendors and unit costs will decrease.

16 The greatest impact on unit costs for 2023 was a higher percentage of more
17 expensive supplemental vendor crews compared to base crews and a higher percentage of
18 backlog circuit miles cleared than anticipated; these additional backlog circuit miles were
19 selected and added with the \$8.0 million in one-time funding from MPSC Case No.
20 U-21332.

21 The greatest impact on unit costs for 2024 was new line clearing contracts executed
22 in the second quarter of 2024. The Company experienced an approximate 12% increase

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1 above inflation in the base rates for line clearing contractors for 2024 when these new
2 contracts went into effect.

3 **Q. Does the Company request to recover the entirety of its LVD line clearing O&M**
4 **spending in the test period through base rates?**

5 A. No, it does not.

6 **Q. Is the Company proposing an alternate mechanism to fund LVD Line Clearing O&M**
7 **in the test period?**

8 A. Yes, the Company is proposing regulatory asset treatment for the funding requirement for
9 the test period above baseline expenditures, identified in Exhibit A-170 (SES-1),
10 column (p), line 27. Figure 23 below summarizes the total O&M expense, baseline
11 expense, and regulatory asset proposal amounts for the test period. This proposed alternate
12 funding mechanism is discussed in further detail in Company witness Daly's testimony on
13 page 34, line 18, through page 36, line 20.

FIGURE 23
LINE CLEARING O&M ALTERNATE FUNDING MECHANISM PROPOSAL
TEST PERIOD

Description	HVD	LVD	Total
Total O&M Expense	\$11,839,660	\$174,844,314	\$186,683,974
Baseline Expense	\$11,839,660	\$152,606,207	\$164,445,867
Regulatory Asset	\$0	\$22,238,107	\$22,238,107

14 **RESOURCING PLAN FOR THE LINE CLEARING PROGRAM VISION**

15 **Q. Does the Company currently have the personnel and other resources to complete the**
16 **projected HVD line clearing work if the Commission approves the requested**
17 **spending level?**

18 A. Yes, the Company currently has the resources in place to maintain the HVD system on a
19 four-year clearing cycle.

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1 **Q. Does the Company currently have the personnel and other resources to complete the**
2 **projected LVD line clearing work if the Commission approves the requested spending**
3 **level?**

4 A. No. At the time of this filing, the Company has not yet secured the personnel and other
5 resources required to execute the full requested spending level, which is an increase over
6 recent annual expenses and current personnel and resourcing levels.

7 **Q. How does the Company plan to meet the personnel and other resource requirements**
8 **to complete the projected LVD line clearing work if the Commission approves the**
9 **requested spending level?**

10 A. A great issue for resource planning is certainty of funding. While the Company will not
11 execute its plans to secure additional personnel and other resources until certainty is
12 attained, the Company is preparing to do so for the test period. The Company has identified
13 three focus areas for this preparation: (i) line clearing contractors; (ii) contract planning
14 and supervision; and (iii) internal staffing.

15 To ensure the necessary crewing is attained, the Company is working with
16 established line clearing contractors to upskill current and hire additional employees to
17 increase the local crew baseline resourcing level. Additionally, the Company is pursuing
18 contracts with supplemental line clearing contractors to provide out-of-state tree crews to
19 meet the increased crew resourcing level needed to execute the ramp-up plan. Figure 24
20 below outlines actual crewing from 2020 through 2024 and the projected crewing plan for
21 2025 through 2030.

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FIGURE 24
HVD AND LVD LINE CLEARING CREWING

Calendar Year	Data Type	HVD	LVD		Total Crews
		Local Crews	Local Crews	Out-of-State Crews	
2020	Actual	41	220	0	261
2021	Actual	42	299	0	341
2022	Actual	38	334	0	372
2023	Actual	38	348	0	386
2024	Actual	38	347	0	385
2025	Projected	38	364	0	402
2026	Projected	38	403	53	494
2027	Projected	38	420	120	578
2028	Projected	38	420	158	616
2029	Projected	38	420	158	616
2030	Projected	38	420	158	616

1 The Company's Forestry Operations and Supply Chain departments are
2 collaborating with its established contract planning vendor for additional planning and
3 supervision resources as well as supplemental contract planning vendors to meet the
4 increased personnel level needed to execute the ramp-up plan.

5 For in-house staffing, the Company continues to recruit graduates from Michigan
6 Technological University, Michigan State University, and other universities that offer
7 degrees in forestry and/or natural resource management. The plan for internal staffing
8 during the ramp-up is set to meet a level to support the baseline to maintain the steady-state
9 five-year cycle; during the ramp-up period, the Company will utilize contract personnel to
10 meet the increased staffing needs over the baseline resourcing level starting in the test
11 period through the five-year vision.

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1 **Q. How does the Company plan to ramp up its LVD line clearing spending and full**
2 **circuit clearing work for the 2026 calendar year and test period?**

3 A. The projected 2026 calendar year increase in O&M expense and LVD full circuit clearing
4 miles is provided in Figure 12 above and in Exhibit A-170 (SES-1) for the test period. As
5 Figure 12 indicates, in the 2026 calendar year, the Company projects to clear 7,891 miles
6 in its full circuit clearing subprogram, which is 1,783 more miles (29% higher) than the
7 projected 2025 full circuit clearing mileage. The Company projects that it will need 92
8 additional contractor line clearing crews above the 2025 crewing level to accomplish this
9 plan in the 2026 calendar year. In partnership with its current vendors under terms
10 established with new contracts executed in the second quarter of 2024, and through the
11 engagement of supplemental vendors, the Company expects to meet this required crewing
12 level.

13 **Q. Does this conclude your direct testimony in this case?**

14 A. Yes, this concludes my direct testimony.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U- 21870

DIRECT TESTIMONY

OF

CAITLIN M. TETRICK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

CAITLIN M. TETRICK
U- 21870 DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

2 A. My name is Caitlin M. Tetrick, and my business address is One Energy Plaza, Jackson,
3 Michigan 49201.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)
6 as the Executive Director of Total Rewards & Workforce Strategy.

7 **Q. Please describe your educational background and work experience.**

8 A. I graduated in 2011 from Michigan State University with a Bachelor of Arts in Journalism.
9 In addition, I graduated from the University of Michigan’s Ross School of Business in
10 2019 with a Master of Business Administration, and hold a certificate for a Senior
11 Professional from the Society of Human Resources (“HR”). I joined Consumers Energy
12 in 2011, and have held non-supervisory positions in Information Technology, Smart
13 Energy, Customer Communications, and Co-worker Communications. I have also held
14 supervisory positions within our Customer Care department and our HR functions,
15 including supervising internal communications, employee experience, workforce planning,
16 People & Culture strategy, and Total Rewards.

17 **Q. What are your responsibilities as Executive Director of Total Rewards & Workforce**
18 **Strategy?**

19 A. My responsibility as Executive Director of Total Rewards & Workforce Strategy is to
20 provide direction to five key functions within the People & Culture department, including
21 Strategic Workforce Planning, People & Culture Strategy, Co-worker Communications,
22 Benefits & Compensation, and Co-worker Experience. Of the functions, Strategic
23 Workforce Planning is most relevant to this testimony.

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That function is responsible for leading and/or executing strategic workforce planning, human resources, and contracted partner management, including responsibility for headcount planning and optimizing resources.

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 projected capital investments and Operating and Maintenance ("O&M") spending in Low Voltage Distribution ("LVD") and High Voltage Distribution ("HVD") with respect to operational resources.

First, I will discuss Consumers Energy's resource needs. Second, I will discuss the Company's resource planning approach, including use of a cross-functional resource planning review process, the importance of leveraging both Company and contracted resources, and the ability of the Company to adequately use our talent pipeline to ensure resource adequacy.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-178 (CMT-1)	Summary of Historical Year, Bridge Period, and Projected Test Year for Operations Resources – Electric LVD Workplan; and

Exhibit A-179 (CMT -2)	Summary of Historical Year, Bridge Period, and Projected Test Year Operations Resources – Electric HVD Workplan.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

1 **Q. How does Consumers Energy plan for the workforce required to deliver the**
2 **Reliability Roadmap, as presented by Company witness Michael P. Kelly, and how**
3 **will it meet these resourcing demands?**

4 A. The Company's requirement for its operational workforce is analyzed using a cross-
5 functional resource planning process that focuses on one to five years of future resource
6 needs.

7 This proactive plan development provides visibility into any resource gaps and
8 adequate time to address those gaps. It also focuses on developing Company resources in
9 a way to provide greater value to the customer by reducing safety risks and developing
10 workforce skills within the Company. These continuously advancing skills are key to the
11 success of the investment work outlined in the Reliability Roadmap, as sponsored by
12 Company witness Kelly as Exhibit A-129 (MPK-19). By executing the plan with a highly
13 trained and safety-minded workforce, the Company will ultimately produce a more reliable
14 and resilient grid.

15 The Company meets its resourcing demands as follows: first, the Company
16 effectively and efficiently scales its workforce capacity to meet its operational workplans,
17 inclusive of its Utility Workers Union of America ("UWUA") and contract workforces.
18 The Company has demonstrated its ability to scale its workforce capacity from 2019
19 through 2024. Total apprentices in the Electric Lines Program have grown from 135 in
20 2019, to 312 in 2024. During that same period, the number of qualified journey line
21 workers in Electric Operations grew from 470 in August 2019, to 550 in December 2024.
22 This growth in the workforce has increased the Company's capacity to deliver work
23 focused on meeting customer needs for a reliable and resilient grid.

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Our planning process constantly evaluates the need for workforce capacity adjustments consistent with the Company's efforts to maintain and improve the electric distribution system. Second, direct hiring and apprentice programs play a key and sustainable part in the Company's approach to secure operational resources and must be commensurately scaled and funded.

Q. Please describe the Company's Electric Lines Apprenticeship Program.

A. It takes four years of training and on-the-job experience to train a journey line worker. The length of time required to train a journey line worker means the Company must have a strong, future-facing workforce plan. As apprentices advance in the Company's program, they can apply various new skills, based on where they would fall in the four steps of the apprenticeship program. In Step I of their apprenticeship, they acquire skills in climbing and can work on energized secondary, string power lines between poles, sagging of conductor, and streetlighting. In Step II of their apprenticeship, they acquire the technical ability to test equipment, install transformers, frame and set poles, and build power banks. In Step III of their apprenticeship, they acquire the skills to conduct work on single phase energized primary, protective equipment, and perform switching. During Step IV of their apprenticeship, they acquire the skillset to install line equipment, remove line equipment, work energized primary climbing, and work multi-phase energized primary. As they advance in the apprenticeship program, they acquire the skills to perform the above tasks safely, and with direct oversight from qualified journeymen, in addition to a joint oversight committee partnered between the Company and UWUA. Each subsequent level of apprentice provides a higher level of value to customers as many of them are focused on reliability-based projects that pertain to their specific skill level.

1 **Q. How is the remainder of your direct testimony organized?**

2 A. The remainder of my direct testimony is organized as follows:

3 I. OVERVIEW OF RESOURCE NEEDS

4 II. RESOURCING APPROACH

5 **I. OVERVIEW OF RESOURCE NEEDS**

6 **Q. What are the Electric Operations resources needed to complete the electric**
7 **distribution workplan?**

8 A. The Company will need to increase both its LVD and HVD Field Maintenance and
9 Construction resources beyond current levels to complete the electric distribution
10 workplan. The change in operational resource needs are as follows:

	2025	2026	2027
LVD	1,229	1,537	1,742
HVD	504	539	530
Total Resources	1,733	2,076	2,272
Growth Percentage (YOY)		20%	9%

11 The projected resources are needed to complete the distribution workplan as described by
12 Company witnesses Andrew R. Snider, Megan L. Hayward, Michael P. Kelly, Scott A.
13 McPhail, Jennifer M. Partlan, and Daniel A. Schmoekel. The costs associated with these
14 resources are sponsored by Company witness Kelly and are summarized in Exhibits A-12
15 (MPK-1), Schedule B-5.7 and A-125 (MPK-15).

16 **Q. How are the projected resource needs determined in Exhibits A-178 (CMT-1) and**
17 **A-179 (CMT-2)?**

18 A. Resource needs are determined by reviewing the various work types, applying historical
19 data using reasonable expectations (historic times for completion of specific work types),

1 and identifying the funding and qualified resource needs required to complete the work
2 plan each year.

3 **II. RESOURCING APPROACH**

4 **Q. What is the Company's approach to identifying its resource needs?**

5 A. The Company uses a cross-functional resource planning process that brings visibility to
6 current and future resource needs, and enables the ability to ensure sufficient resources are
7 available at the right times to meet demand. By evaluating future resource requirements,
8 the Company can make sure essential workplans are achievable and plans are in place to
9 fill any identified gaps through appropriate countermeasures.

10 Resource needs are determined based on the level of investment in programs such
11 as Demand Failures, New Business, Reliability, Capacity, and Asset Relocation. These
12 resource needs are translated into work hours needed to support the entire workplan. When
13 gaps are identified, the planning team works together to identify countermeasures and
14 prioritize the workplan. Employee safety, customer experience, and efficient use of
15 resources are each part of the balanced approach that drives the mix of countermeasures
16 selected.

17 Longer-term choices, such as adding apprentices, are the result of long-term work
18 plan projections, and improve our capability to deliver in the future as demands increase,
19 such as those outlined in the Reliability Roadmap.

20 The Company is taking proactive measures to significantly increase its capability
21 to execute the Reliability Roadmap. These measures include direct hiring and
22 apprenticeships as well as contractor networks, each with an emphasis on building scalable
23 and effective local workforces. Various skilled resources are needed for Electric

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1 Operations, including LVD line workers, HVD line workers, electric underground line
2 workers, electric field lab employees, substation operators and maintenance personnel, and
3 grid management personnel. The Company is exploring alternative resourcing strategies
4 that enable resources to be deployed quickly. First, in December of 2024, the Company
5 began direct hiring of qualified Journey Line Workers. Overall efforts were positive,
6 resulting in hiring 20 qualified workers as part of the effort. Recruiting efforts for 2026
7 resources will begin in the fall of 2025 to ensure resources can be onboarded for the test
8 year of the case. To enhance recruitment efforts, the Company plans to engage with a
9 search firm to identify qualified Journey Line Workers seeking a career move. Marketing
10 materials will be updated to highlight the benefits of working at Consumers Energy. Social
11 media and radio advertising will be used as well. Secondly, the Company intends to fill
12 some of the necessary positions by re-skilling J.H. Campbell plant employees. Currently,
13 70 positions, from Basic Line Apprentices to Underground Line Workers, are being held
14 to re-deploy resources to support this initiative as the Company transitions away from
15 coal-fired generation and executes upon its Integrated Resource Plan that was approved in
16 Case No. U-21090.

17 Securing the workforce needed to do this work is a vital part of the Company's
18 ability to achieve the improved reliability that the Reliability Roadmap is meant to deliver.
19 The Company intends to secure the additional labor resources needed to achieve the plan
20 and will continue to move toward these increased workforce goals, but it must have
21 certainty of long-term support for this plan.

A. LVD Maintenance and Construction

Q. How many LVD workers does the Company currently utilize?

A. As of December 31, 2024, the Company uses 1,017 full-time Consumers Energy LVD field workers to complete LVD maintenance and construction work. In addition, the Company has divided the state into four zones with contracts competitively bid and awarded to provide contractor support for each zone. Furthermore, the four zone contractors and numerous additional contractors may participate in specific bids or provide resources for ongoing workload, where additional resources are needed for specific project work or to balance internal crewing capacity.

Q. How many LVD workers does the Company anticipate needing for the projected test year?

A. The Company anticipates needing 1,742 workers to complete the work in the projected test year as shown in Exhibit A-178 (CMT-1), which provides an overview of the Company's operational resource needs for the LVD workplan.

Contractor resources will flex up or down to complement the work being performed by our internal crews. Contractor resources may also be flexed up or down based on the nature of the work being performed or based on the availability of our crews relative to the total workplan.

Q. How does the Company determine the number of resources that are needed to complete distribution workplans?

A. Workforce needs are determined by historical workplans, projected capital and O&M, and estimated attrition levels.

1 **Q. How does the Company build and maintain the LVD and Underground workforces**
2 **required to complete the planned distribution work?**

3 A. The Company negotiated contractual agreements with the UWUA in 2020 to hire 72
4 apprentices in 2023, and 72 apprentices in 2024. The hiring of additional apprentices
5 aligned with current attrition rates and projected workplans to build a correctly sized LVD
6 workforce. This yielded hiring of 348 Journey Line Worker Apprentices between
7 2021-2024. The Company is direct-hiring skilled LVD workers, as well as using
8 apprenticeship programs with community colleges, a Veterans Hiring Program, and the
9 UWUA. The Company has expanded its work with additional community colleges,
10 allowing an extended reach into communities, targeting increased diversity and a long-term
11 reduction of internal transfers by virtue of initially hiring employees into the regions they
12 want to live in long term.

13 Specifically, the Company initiated partnerships with strategic community colleges
14 located across Michigan including Jackson, Flint, Alpena, and Lansing in 2008 to host line
15 worker pre-apprenticeship programs. These programs, like the School to Work (“STW”)
16 Program, provide skilled trade training opportunities. The STW Program has yielded great
17 success as 74% of the Company’s apprentice line worker hires have come through the
18 program since 2014.

19 **B. HVD Maintenance and Construction**

20 **Q. What workforce does the Company utilize to perform HVD line work?**

21 A. The Company uses a contractor workforce to complete HVD line maintenance,
22 construction, and restoration via a competitive bidding process. In addition, the primary

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1 HVD contractors and numerous additional contractors may participate in specific bids for
2 more complex HVD project work.

3 The Company works closely with its primary HVD contractors to ensure awareness
4 and visibility into the workplan to ensure cost effectiveness, stability, and growth of the
5 HVD workforce as needed to support the plan. HVD line contractors are only approved to
6 work on the HVD side of lines, with the exception of restoration activities, where LVD
7 restoration is needed.

8 **Q. What workforce does the Company utilize to perform HVD substation work?**

9 A. The level of complexity of HVD substation work, along with the optimized planned use of
10 resources, drives the decision making for which workforce to use for substation work.
11 Maintenance work, emergent repairs, and short-cycle planned work are often completed
12 by Company employees in the HVD Substation Maintenance group. A competitive bid
13 process is used for engaging dedicated resources or part-time contractors for influxes of
14 work or within planned specific projects.

15 **Q. What are the Company's HVD workforce needs for the projected test year?**

16 A. Exhibit A-179 (CMT-2) provides an overview of the Company's operational resource
17 needs for the HVD workplan.

18 **Q. Does this complete your direct testimony?**

19 A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21870

DIRECT TESTIMONY

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

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1 **Q. Please state your name and business address.**

2 A. My name is Brian J. VanBlarcum, and my address is One Energy Plaza, Jackson, Michigan
3 49201.

4 **Q. By whom are you employed?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

6 **Q. What is your position with Consumers Energy?**

7 A. I am a Tax Director in the Company’s Corporate Tax Department.

8 **Q. Please briefly describe your educational background.**

9 A. I am a graduate of Western Michigan University where I earned a Bachelor of Business
10 Administration degree in Finance.

11 **Q. Please describe your business experience.**

12 A. I started with the Company in 2004 as a General Accounting Analyst with the Company’s
13 property accounting team. In 2019, I was appointed to my current position as Tax Director
14 with the Company’s Corporate Tax Department.

15 **Q. Are you a certified assessor?**

16 A. I am a Michigan Certified Assessing Officer certified by the State of Michigan’s State Tax
17 Commission and a member of the Michigan Assessors Association.

18 **Q. What are your responsibilities as Tax Director?**

19 A. I am responsible for the administration of the Company’s real and personal property taxes.
20 This includes: (i) managing the Company’s self-declaration of personal property located
21 within the state of Michigan; (ii) overseeing property tax matters concerning the
22 Company’s land, generating sites, and other real property; and (iii) supervising tax
23 payments to approximately 1,500 taxing authorities. I am also responsible for the

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1 calculation of federal and state tax depreciation related to the Company's fixed assets and
2 the associated deferred income taxes.

3 **Q. Have you previously testified before the Michigan Public Service Commission**
4 **("MPSC" or the "Commission")?**

5 A. Yes, I sponsored testimony in the following cases:

- 6 • Gas Rate Case No. U-15506;
- 7 • Electric Rate Case No. U-15645;
- 8 • Electric Rate Case No. U-16191;
- 9 • Gas Rate Case No. U-16418;
- 10 • Electric Rate Case No. U-17087;
- 11 • Electric Rate Case No. U-17735;
- 12 • Gas Rate Case No. U-17882;
- 13 • Electric Rate Case No. U-17990;
- 14 • Gas Rate Case No. U-18124;
- 15 • Electric Rate Case No. U-18322;
- 16 • Gas Rate Case No. U-18424;
- 17 • Electric Rate Case No. U-20134;
- 18 • Gas Rate Case No. U-20322;
- 19 • Gas Rate Case No. U-20650;
- 20 • Electric Rate Case No. U-20697;
- 21 • Gas Rate Case No. U-21148;
- 22 • Electric Rate Case No. U-21224;
- 23 • Electric Rate Case No. U-21389;

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- Gas Rate Case No. U-21490;
- Electric Rate Case No. U-21585; and
- Gas Rate Case No. U-21806.

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 April 30, 2027) and explains how the rate was derived. I am also supporting the amount of test year excess deferred federal income taxes being returned to electric 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 proceeding, Case No. U-20309.

Q. Have you prepared any exhibits to accompany your direct testimony?

A. Yes. I am sponsoring:

Exhibit A-180 (BJV-1)	Development of the Property Tax Rate for the Test Year; and

Exhibit A-181 (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.

Development of the Property Tax Rate for the Test Year

Q. What is the Property Tax Rate for the test year?

A. As indicated on Exhibit A-180 (BJV-1), page 1, line 18, the Property Tax Rate for the test year is 0.013349387.

Q. How did you calculate the Property Tax Rate for the test year?

A. The Property Tax Rate for the electric business was calculated using the Company’s prorated Electric Property Tax Expense, shown on Exhibit A-180 (BJV-1), page 1, line 11,

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divided by the total of the 2026 Estimated Year-End Plant-in-Service, shown on Exhibit A-180 (BJV-1), page 1, line 12, plus one-half of the 2026 Estimated Construction Work-in-Progress, shown on Exhibit A-180 (BJV-1), page 1, line 15.

Q. What is included in the Electric Property Taxes Paid – 2026 Estimate on Exhibit A-180 (BJV-1), page 1, line 1?

A. The 2026 taxes paid by Consumers Energy of \$281.9 million on behalf of the electric portion of the business represents the estimated property taxes to be paid in 2026.

Q. What is included in the Electric Property Taxes on 2026 Plant Investment on Exhibit A-180 (BJV-1), page 1, line 2?

A. The \$33.6 million increase is the estimated property taxes on the 2026 net additions that will be included in the 2027 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 49.7863 to obtain the estimated tax amount. This calculation is shown on Exhibit A-180 (BJV-1), page 2, line 9.

Q. What is included in the 2027 Fossil Plant Valuation Tax Reduction on Exhibit A-180 (BJV-1), page 1, line 3?

A. The \$0.1 million decrease reflects a reduction in property taxes associated with the D.E. Karn Plant (Units 3-4). The reduction in property taxes is the result of successful negotiations with the local unit of government over the taxable value of the Company's fossil fuel-fired electric generating facilities.

1 **Q. What is included in the Electric Property Taxes on Real Property Taxable Value**
2 **Increases on Exhibit A-180 (BJV-1), page 1, line 4?**

3 A. The \$1.2 million increase for the Real Property Taxable Value relates to the Michigan
4 Constitution of 1963, Article IX, Section 3, allowing local assessors to raise real property
5 taxable values by the lesser of 5% or the Consumer Price Index ("CPI"). For 2027, the
6 Company's property tax model assumes a CPI rate of 2.4%. This calculation is shown on
7 Exhibit A-180 (BJV-1), page 3.

8 **Q. What is the result of including the Electric Property Taxes on 2026 Plant Investment,**
9 **2027 Fossil Plant Valuation Tax Reduction, and Electric Property Taxes on Real**
10 **Property Taxable Value Increase on the estimated 2027 property tax amount paid by**
11 **the electric business?**

12 A. The result of including these additional items is an estimated 2027 property tax amount to
13 be paid for the electric business of \$316.6 million, as shown on Exhibit A-180 (BJV-1),
14 page 1, line 5.

15 **Q. Does the amount on Exhibit A-180 (BJV-1), page 1, line 6, include property tax**
16 **payments for pollution control equipment or computer software, such as SAP?**

17 A. No, as pollution control equipment and computer software are exempt under
18 MCL 324.5904(1) and MCL 211.9d, the estimate of 2027 property tax to be paid on line 6
19 does not include property taxes associated with these items.

20 **Q. How is this paid amount converted to an expense amount?**

21 A. Since the Company expenses property taxes based on the fiscal year of the taxing
22 authorities, 50.0% of the 2026 estimated electric property tax payments for Consumers
23 Energy is added to the 2027 estimated electric payments since that amount will be expensed

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1 in 2027, while subtracting 50.0% of the 2027 estimated electric payments that will be
2 expensed in 2028, arriving at a total 2027 electric property tax expense of \$299.3 million
3 as shown on Exhibit A-180 (BJV-1), page 1, line 8.

4 **Q. What is the next step in calculating the tax rate for the test year?**

5 A. For the test year, property tax expense was prorated for the period of May 1, 2026 through
6 April 30, 2027 using a monthly budgeted sales percentage applied to the 2026 and 2027
7 estimated annual property tax expense amounts. The result of factoring property tax
8 expense monthly for the test period is a prorated Electric Property Tax Expense of
9 \$280.5 million, as shown on Exhibit A-180 (BJV-1), page 1, line 11. The prorated Electric
10 Property Tax Expense for the test year is divided by the 2026 Estimated Year-End Plant-
11 in-Service plus one-half of 2026 Estimated Construction Work-in-Progress to arrive at a
12 property tax rate of 0.013349387.

13 **Q. On March 21, 2025, in Case No. U-21585, the Commission supported the**
14 **Administrative Law Judge's recommendation that, "Consumers continue to provide**
15 **a list of pending tax assessment litigation cases and negotiations in rate case filings**
16 **going forward." Does the Company have any current property tax litigation?**

17 A. No. The Company is not currently involved in property tax litigation at this time.

18 **Amortization of Excess Deferred Federal Income Taxes for the Test Year**

19 **Q. On September 26, 2019, in Case No. U-20309, the Commission issued an Order in the**
20 **Company's Calculation C case. What specific issues did the September 26, 2019**
21 **Order address?**

22 A. The Commission's September 26, 2019 Order in the Company's Calculation C case
23 authorized the amount and time period under which the Company will refund to electric

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1 customers \$1,174,181,000 of excess deferred federal income taxes as a result of the TCJA
2 lowering the corporate income tax rate from 35% to 21%. As part of the settlement terms
3 in Case No. U-21224, the Commission approved an adjustment to reduce this amount by
4 \$4,168,278 to correct an overstatement of the TCJA remeasurement. The Commission
5 authorized three different amortization periods: (i) Protected plant balances over an
6 amortization period determined using the Average Rate Assumption Method (“ARAM”);
7 (ii) Non-Protected plant balances amortized over 27 years; and (iii) Unprotected non-plant
8 balances amortized over 10 years. Exhibit A-181 (BJV-2), page 2, referenced as
9 Exhibit A-5 (SBM-3) in Case No. U-20309, provides the projected annual amortization of
10 these balances based on the periods approved by the Commission.

11 **Q. What additional amount of excess deferred taxes related to the TCJA has the**
12 **Company proposed to refund to customers in this case?**

13 A. As shown on Exhibit A-181 (BJV-2), page 1, line 22, the Company has proposed to refund
14 an additional \$7,907,000 of excess deferred taxes (\$10,604,000 of regulatory liability after
15 gross-up for taxes) in this case. This amount represents the Company’s regulatory liability
16 recorded as of year-end 2022 which was calculated as the difference between the actual
17 amount of excess deferred taxes for the year and the estimated amount included in rates.
18 The Company’s most recently filed report to the Case No. U-20309 docket, which
19 calculates the \$10,604,000 regulatory liability balance, is included as Exhibit A-181
20 (BJV-2), page 3.

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1 **Q. Based on the Commission's September 26, 2019 Order in Case No. U-20309 and the**
2 **additional amount described above, what amount of excess deferred federal income**
3 **tax has the Company proposed to return to customers in this case?**

4 A. Exhibit A-181 (BJV-2), page 1, provides a calculation of the test year excess deferred
5 federal income taxes included in this case based on the periods approved by the
6 Commission in Case No. U-20309. Overall, the Company reduced Federal Income Tax
7 Expense for the test year by \$40.434 million to reflect the amortization periods and
8 amounts discussed above. This amount is shown on Company witness Patrick D. Daly's
9 Exhibit A-13 (PDD-45), Schedule C-8, lines 45, 46, and 47 as TCJA Tracker, TCJA
10 Amortization – ARAM and TCJA – Non-ARAM.

11 **Q. Are the excess deferred federal income tax amounts refunded to electric customers in**
12 **the test year estimates or actuals?**

13 A. The amounts included in this case are estimates as the Commission's September 26, 2019
14 Order in Case No. U-20309 requires an annual reconciliation of the actual amount of excess
15 deferred federal income tax in a given year and the estimated amount included in rates.
16 The Company will file this reconciliation in Case No. U-20309 by March 31st of each year.

17 **Q. Does this conclude your direct testimony?**

18 A. Yes.