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-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

MICHAEL A. TORREY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

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

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or "the Company") as its Vice President, Rates and Regulation.

Q. Please describe your educational background.

A. I graduated from the University of Michigan-Flint in 1982 with a Bachelor of Business Administration in Accounting degree, and in 1992, I earned a Master of Business Administration degree with a finance major from Western Michigan University. I have also completed courses and seminars in utility accounting, economics, finance, and ratemaking.

Q. Please describe your professional experience.

A. In May 1983, I joined Consumers Energy's Nuclear Operations Department as a Graduate Accountant assigned to the Controllers Department at the Palisades Plant. I progressed through several levels of increasing responsibility during my Palisades Plant assignment, achieving the position of Senior Accounting Analyst in April 1993. In July 1998, I was appointed Director of Revenue Requirements, Cost Analysis and Planning in the Company's Rates Department. In December 2006, I was promoted to Executive Director-Rates. In March 2015, my responsibilities were expanded to include Regulatory Affairs. In July 2016, I was promoted to Vice President, Rates and Regulation.

Q. What are your responsibilities as Vice President, Rates and Regulation?

A. I am responsible for ratemaking and regulatory activities at Consumers Energy, including revenue requirements, cost of service, rate design, tariff administration, Consumers Energy's Michigan Public Service Commission ("MPSC" or the "Commission") compliance program, as well as regulatory affairs and policy.

Q. Are you a member of any professional organizations?

A. Yes. I am a member of the Institute of Management Accountants, a worldwide association of accountants and finance professionals. I also belong to Beta Gamma Sigma, the honor society of the business school accreditation organization the Association to Advance Collegiate Schools of Business. In addition, I am a member of School of Management's Advisory Board at the University of Michigan – Flint.

Q. Have you previously testified before the Commission?

A. Yes. I have sponsored testimony in the following Consumers Energy cases:

U-12891	Electric Restructuring Implementation Costs;
U-13000	Gas General Rate Case;
U-13380	Stranded Cost;
U-13720	Stranded Cost;
U-13715	Securitization;
U-14098	Stranded Cost;
U-14274	Power Supply Cost Recovery ("PSCR") Plan;
U-14347	Electric General Rate Case;
U-14992	Palisades Sale;
U-14981	Midland Cogeneration Venture Limited Partnership Sale;

U-15290	Balanced Energy Initiative;
U-15415	PSCR Plan;
U-15611	Big Rock Decommissioning Reconciliation;
U-16191	Electric General Rate Case;
U-16861	Department of Energy Litigation Settlement Proceeds;
U-17473	Power Plant Securitization;
U-17990	Electric General Rate Case;
U-18124	Gas General Rate Case;
U-18322	Electric General Rate Case;
U-18424	Gas General Case;
U-20134	Electric General Rate Case;
U-20165	Integrated Resource Plan;
U-20322	Gas General Rate Case; and
U-20650	Gas General Rate Case.

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

A. The purpose of my testimony is to provide an overview of the Company's electric general rate case. First, my testimony provides an overview of Consumers Energy and its commitment to people, the planet, and Michigan's prosperity. My testimony then identifies key drivers that led to the filing of this case, and why the Company's proposals included in this case are in the best interest of our customers and Michigan. Following a review of the key drivers, I provide a summary of the impact on customer bills. Finally, my testimony introduces the direct testimony offered by the other Company witnesses.

Q. Why has the Company initiated this proceeding?

A. Consumers Energy initiated this request because the Company has made – and continues to make – significant investment in its electric system. That investment has allowed the Company to update its metering infrastructure and make improvements to its energy supply and delivery system that have benefitted customers through increased safety, reliability, and an improved customer experience. While a lot has been accomplished in the last decade to enhance the Company's electric system, there is still more to be done. Many assets on the electric distribution system are reaching the end of their expected life, leading to increased vulnerability to storms which negatively impacts reliability. In addition, the Company is taking steps to advance its clean energy goals by eliminating coal and the impact of carbon emissions to achieve net zero emissions by 2040.

The Company has been transparent about the magnitude of the work that remains through its Electric Distribution Infrastructure Investment Plan ("EDIIP") and Integrated Resource Plan ("IRP"), two plans that serve as the foundation to the Company's electric strategy. The proposals included in this case build on those plans and put the Company on a path to excel at the basics – providing customers with safe, reliable, and affordable electric service with best in class customer service – and build for the future to enable the transition to a cleaner and more efficient energy system.

Q How will customers benefit from the proposals included in this case?

A. The Company's proposals in this case offer reliability, clean energy, and customer experience benefits and provide significant value to customers. Chief among those benefits are system reliability improvements that will reduce the number and frequency of customer outages. Collectively, the Company's reliability investments included in this case put the

Company on a glidepath to achieve a System Average Interruption Duration Index ("SAIDI")[1] performance of 170 minutes by 2025, a reduction of 28 outage minutes compared to 2020 projected performance.[2] The investment included in this case also puts the Company on track to execute and deliver on the benefits articulated in the IRP which include ending coal use by 2040 and expanding reliance on demand-side resources that will help keep Michigan energy costs affordable for all customers. In addition, the Company is undertaking several projects that will enhance our ability to effectively communicate and interact with customers and improve the overall customer experience. This case includes initiatives that will improve storm and outage communications and online work scheduling; for example, the addition of a service tracker that will allow customers to track service orders through a web application. The Company is also adding a streetlight application that will allow customers to report streetlight outages and receive follow-up information such as restoration status. The Company can deliver the benefits detailed in this case to customers all while keeping the average residential bill below the national average, with customers experiencing a tremendous value for less than $4.00 a day for electricity in the test year (2021).

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

I. Company Overview

II. Key Drivers

III. Customer Impact

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[1] SAIDI is a measurement of the average number of minutes per year that a typical electric customer is without electric service. SAIDI is the primary measurement of system reliability used by Consumers Energy to evaluate electric distribution system reliability.

[2] 2020 projected SAIDI performance of 198 minutes per Company witness Richard T. Blumenstock.

IV. Introduction of Witnesses

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

A. No, I am not.

I. COMPANY OVERVIEW

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

A. Consumers Energy is a combination electric and gas utility that has powered Michigan's progress for over 130 years. Today, the Company provides safe, reliable, affordable, and increasingly clean electricity to 1.8 million customers in all 68 of Michigan's counties in the Lower Peninsula. Consumers Energy is driven by its purpose to achieve world-class performance delivering hometown service, measured by a triple bottom line – people, the planet, and Michigan's prosperity.

Q. Please explain.

A. The Company's focus on a triple bottom line means measuring success on people, the planet, and prosperity. The triple bottom line balances the interests of customers with other stakeholders and captures the broader societal impacts of the Company's activities. The triple bottom line allows us to balance the interests of all those who count on us – not at the expense of one another – and is essential to our success now and in the future.

1. People

The Company is committed to its customers, employees, and every Michigan resident. Central to this commitment is providing safe, reliable, and affordable electric service and supporting the people we serve through community engagement and volunteerism. The Company's commitment to people also means providing customers with a great customer experience – what employees at Consumers Energy refer to as providing hometown service.

2. Planet

The Company is committed to its Clean Energy Goal that goes beyond what is required by current law and illustrates the Company's commitment to protecting the environment. In the Clean Energy Plan, which was outlined in the IRP approved by the Commission in June 2019, Consumers Energy committed to reduce 90% of the carbon emissions it generates by eliminating the use of coal and working with customers to use energy more efficiently. The Company has recently announced that it will take that goal a step further, committing to achieve net zero carbon emissions by 2040. Consumers Energy is proud to forge a path into a cleaner, more sustainable energy future.

3. Prosperity

Consumers Energy is committed to Michigan's prosperity. A prosperous Michigan cannot exist without a financially healthy utility that provides safe, reliable, affordable and increasingly clean energy. The significant funding the Company receives each year from investors and lenders makes the electric system infrastructure replacements and enhancements that benefit our customers and the state of Michigan possible. Ensuring Michigan's prosperity also includes investing in our local communities and supporting local nonprofits in addition to helping Michigan businesses grow.

Q. How has the triple bottom line driven the Company's proposals in this case?

A. Everything the Company does – including the proposals in this case – is guided by the Company's commitment to people, the planet, and Michigan's prosperity. The EDIIP and IRP, which provide the foundation for many of the Company's proposals in this case, were developed to deliver on the triple bottom line. The key drivers in this case build on the plans outlined in the EDIIP and IRP which focus on two key areas; exceling at the basics – providing customers with safe, reliable, and affordable electric service with best in class customer service – and building for the future to enable the transition to a cleaner and more efficient energy system.

Q. Please elaborate on the key drivers in this case.

A. To provide customers with the service they expect now, and in the future, the Company must first and foremost provide customers with safe, reliable and affordable service. One of the key drivers in this case is continued investment to improve system reliability and safety. The Company's EDIIP identified areas where investment is needed to improve the safety and reliability of the electric distribution system. While the Company has made significant investments to enhance system reliability over the years, the Company continues to be challenged by the size and scope of its aging infrastructure. More frequent and severe storms and tree overgrowth in Company right-of-ways pose significant challenges to reliability.

Another key driver is investment that will enable the Company to build for the future. As described in the Company's EDIIP and IRP, the Company is thoughtfully moving from large, baseload generating plants to cleaner, more efficient, and more modular resources. The Company's IRP committed to significant investment in demand-side resources including Energy Waste Reduction ("EWR"), Demand Response ("DR"), and Conservation Voltage Reduction ("CVR"). The Company is also growing its investment in solar energy, pursuing battery storage, and investing in grid modernization which will allow the interconnection and integration of these resources into the distribution system and enable the development and growth of Distributed Energy Resources ("DER"). The future electric distribution system will need to be dynamic, responsive to customers, and integrate these new sources of energy.

II. KEY DRIVERS

A. Key Driver 1: Excel at the Basics – Electric Distribution System Safety and Reliability

Q. What actions has the Company taken over the last few years to address system reliability?

A. Over the past 10 years, Consumers Energy has invested over five billion dollars in its electric distribution system to replace and upgrade High Voltage Distribution ("HVD") and Low Voltage Distribution ("LVD") infrastructure and to overhaul its metering infrastructure, among other things. Where the Company has invested in the system, customers have seen the benefit. For example, as described in greater detail in the testimony of Company witness Richard T. Blumenstock, where HVD lines have been rebuilt there have been 97% less outages on those lines. Additionally, customers in areas where there has been targeted investment in local circuit infrastructure have seen significant improvements to reliability. In the Wyoming Park circuit zone, for example, the Company replaced old and deteriorating poles, pole top structures, and conductor in 2017. As a result, the number of outages in the Wyoming Park zone went from two to four outages per year[3] to zero outages in 2018 and 2019, an improvement which saved customers approximately 815,000 annual outage minutes. This is just one of many examples across the thousands of circuits on the LVD system where the Company's investment in local circuits provides immediate benefits to those customers connected to

[3] Equipment failures per year beginning in 2014

the circuit and contribute to improvements in overall system-wide SAIDI performance. Lastly, aside from asset replacement and upgrades, the Company has also invested to modernize its system for additional reliability benefit. For example, in 2019, the Company deployed 24 distribution automation loops which saved 30,800 customer-interruptions, totaling 9.5 million customer-outage minutes, or about 5.2 SAIDI minutes. The Company also upgraded 179 HVD substations with highspeed communications to enable enhanced security, compliance, and increased communication reliability. On the LVD system, 50% of the Company's substations now have real-time telemetry and automation capabilities – thereby greatly improving situational awareness and control capabilities for improved response and customer restoration time.

Q. What are the current challenges to system reliability?

A. Many assets on the electric system are reaching the end of their expected life, leading to increased deterioration and vulnerability to wind and storms which negatively impact reliability. While the Company has been able to make significant improvements to reliability on circuits that have been targeted for investment, at current funding levels the Company is challenged to keep up with system deterioration, let alone make further improvements to the system. In addition to aging infrastructure, the frequency and severity of storms has increased over the last few years, contributing to an upward trend in outages. Vegetation overgrowth also challenges reliability; over the last six years (2014-2019) outages due to tree contact have almost doubled and continue to trend higher at current funding levels.

The Company described the magnitude of the work in its EDIIP and IRP which were filed with the Commission in March and June of 2018, respectively. While the vision and challenges articulated in those plans have not changed, the scale of the investment in the EDIIP has evolved as the Company obtains additional data that provides a more comprehensive and accurate assessment of overall system condition, particularly for LVD assets.

Q. What steps is the Company taking to address the current challenges to system reliability?

A. The Company is committed to addressing these challenges and improving system reliability. Current capital investment and maintenance spending levels, however, are insufficient to make meaningful improvements to reliability which has led the Company to file this rate request. Therefore, the Company proposes to increase investment in those areas that cause a majority of the outages on the electric system: weather (storm restoration), trees (line clearing), and equipment failure (HVD and LVD Infrastructure). By targeting investment in these areas, the Company can make significant improvements to system reliability.

Q. What are some of the key initiatives and investment included in this case that will address the challenges cited above and improve reliability?

A. The Company proposes targeted investments in the areas that cause a majority of the outages on the electric system: weather (storm restoration), trees (line clearing), and equipment failure (HVD and LVD Infrastructure). Taken together, the reliability investment included in this case put the Company on track to achieve a SAIDI target of 170 minutes by 2025, a reduction of 28 outage minutes compared to 2020 projected performance. Improvements in SAIDI provide significant benefits to local communities; Company witness Brenda L. Houtz estimates that in 2019 electric outages throughout the state cost communities $2.5 billion or $3.6 million per SAIDI minute. Reducing SAIDI by 28 minutes would provide a $100.8 million benefit in avoided costs for customers and local communities.

1. Investment in HVD and LVD Infrastructure

The Company's electric distribution assets are aging and reaching the end of their expected life, leading to increased deterioration and vulnerability to wind and storms which negatively impact reliability. To address its aging infrastructure, as described in the testimony of Company witness Blumenstock, the Company proposes to increase its distribution capital spending[4] by $93.8 million from $628.9 million in 2019 to $722.7 million in the 2021 test year. That includes an increase of $101.0 million in investment (from $230.2 million in 2019 to $331.2 million in 2021) in the Company's Reliability Program. The majority of the increase in the Reliability Program is in rehabilitation projects that target equipment at imminent risk of failure, rather than addressing such issues through the Demand Failures[5] Program. Significant rehabilitation projects in this case include a rebuild of the aging Morrow, Twining, and Higgins HVD substations, with the Morrow and Higgins projects taking place over two years. In addition to these rehabilitation projects, the Company proposes to increase spending on line rebuilds, prioritizing those lines that are the most deteriorated. Line rebuilds substantially improve the performance of a line, reducing or eliminating outages and thus interruptions to customers. Reliability significantly increases in areas where the Company replaces its

[4] As discussed in the testimony of Company witness Blumenstock, electric distribution capital spending is broken into six programs: New Business, Reliability, Capacity, Demand Failures, Asset Relocation, and Electric-Other.
[5] The Demand Failures Program addresses issues related to customer interruptions and failures of equipment on the distribution system.

aging electric infrastructure. Increasing the investment in HVD and LVD infrastructure is critical for the Company's achievement of 170 SAIDI minutes by 2025.

2. Line Clearing

Trees are the greatest cause of interruptions to electric service for our customers on the LVD system; line clearing and vegetation management are important proactive measures that can significantly reduce outages and mitigate the impact of storms and severe weather. As explained in greater detail in the testimony of Company witness Chris A. Shellberg, the Company is proposing to begin moving from a 14.2-year effective tree trimming cycle on the LVD system to a seven-year effective cycle. A seven-year effective cycle is the optimal cycle length given the miles and type of voltages on the Company's system. Moving to a seven-year LVD trim cycle will reduce the number of tree-related outage incidents by over 2,700 per year in 2025 and will reduce SAIDI by 26 minutes or over 90% of the total SAIDI reduction projected in this case. As a result, by 2025 service restoration Operating and Maintenance ("O&M") is projected to decrease by $2.9 million and local communities are expected to realize roughly $93.6 million per year in lost revenue savings. In the test year, the Company is proposing to spend $84.0 million, compared to $53.0 million spent on line clearing in 2019 and planned to be spent in 2020, respectively; much of this increase ($29.9 million) is to begin moving toward a seven-year LVD trim cycle. The increase requested in this case is the first step of several increases needed to begin trimming on a seven-year cycle by 2025 and is the amount that the Company can effectively resource and spend in 2021.

3. Service Restoration

Outage events are extremely costly, both to the utility when the Company responds, and to customers via lost productivity, damage, and inconvenience. As described in greater detail in the testimony of Company witness Houtz, over the last few years the Company has experienced more frequent and extreme weather events that have challenged service reliability. Wind speeds, for example, have worsened contributing to an increase of 7,600 storm incidents over the last five years. Funding levels have not kept pace with the Company's actual storm restoration expense; over the last three years the Company has spent an average of $65 million annually. In 2019, the Company spent over $92 million on storm restoration.[6] Responding to storms and restoring customers can come at the expense of other utility programs as funding and resources are diverted to support the storm response effort. The Company has historically purchased storm insurance to provide additional protection, however, in 2019 the Company cancelled its policy as the cost of the required premium payment exceeded the anticipated claim recovery. In this case, the Company is proposing to include $65 million in service restoration O&M in base rates which is in line with historical storm restoration expense. The Company also proposes to defer storm restoration O&M that exceeds $75 million or which exceeds $10 million above the amount included in rates and amortize those costs over 10 years, as explained in greater detail by Company witness Daniel L. Harry. While storm restoration expense is trending up, as described by both Company witnesses Shellberg and Houtz, movement toward a seven-year LVD line clearing cycle will positively affect the number of storm related outages and ultimately reduce service restoration expense. With increased funding directed

[6] Preliminary actual 2019 service restoration costs.

toward reducing the number of tree related outages in the test year, there is potential to save $0.4 million in 2021 which will increase to approximately $2.9 million beginning in 2025. These savings are in addition to the savings customers and communities realize from experiencing fewer outage events.

4. Workforce Development

To enable the Company to deliver on its plans to increase its reliability spend in the aforementioned areas, the Company needs to secure additional resources. To that end, the Company has developed a resource sufficiency plan, explained in greater detail by Company witness Douglas E. Detterman, that will allow the Company to scale up its resources in the test year and perform the work outlined in the proposals in this case. Workforce and resource plans specific to the execution of the Company's line clearing work is discussed in greater detail in Company witness Shellberg's testimony. As noted by Company witness Shellberg, the test year line clearing work will require the addition of approximately 200 contractor full-time equivalent employees above current levels. The Company, in partnership with its contractors, expects to meet this required staffing level under existing contract terms.

Q. Does the Company have other proposals for increased investment to support and enhance system reliability?

A. Yes. Investing in and maintaining the Company's Information Technology ("IT") systems, which support the operation of the Company's critical infrastructure and customer service functions, is necessary to ensure safe and reliable service. As described in greater detail in the testimony of Company witness Jeffrey D. Tolonen, increasing cybersecurity risk, security requirements, a growing technology asset base, and movement toward cloud solutions has driven higher operational O&M expense. In the past, the Commission has only allowed recovery of the Company's historical five-year average of IT operational O&M expense which has limited the resources available to support existing and new IT investment approved by the Commission. As noted by Company witness Tolonen, limiting approval of IT operational O&M to the historical five-year average, which is substantially lower than the amount requested in this case, would significantly limit the Company's ability to adequately support and maintain the IT infrastructure installed by the Company to serve its customers. Investment and support of the Company's IT infrastructure is just as critical to ensuring system safety and reliability as the investment and support of the Company's lines and wires that deliver electricity to customers.

B. <u>Key Driver 2: Building for the Future</u>

Q. Please explain how the electric distribution system is changing.

A. The electric grid is evolving faster than ever as technology advances and customer expectations change. The Company has historically operated large baseload generation that included nuclear, coal, and other fossil fuels with some reliance on renewable energy resources. As set forth in the Company's approved IRP, the Company is shifting from large, baseload generating plants to cleaner, more efficient, and more modular generation resources. Utilizing more modular resources allows the Company to meet its commitment to keeping bills affordable, limiting risk to customers, and transitioning to a cleaner resource portfolio. The Company believes that a clean and lean approach is the most reasonable and prudent way to meet energy and capacity needs over the long term. That is why the Company has committed to end coal use by 2040 and expand its reliance on demand-side resources. Demand-side resources, which include EWR, CVR, and DR resources help keep Michigan energy costs affordable for all customers, even those who do not participate. The Company is also planning for an expansion of DER, increasing its investment in solar energy, pursuing battery storage, and employing other grid modernization tools. The future electric distribution system will need to be dynamic, responsive to customers, and integrate these new sources of energy.

Q. What are some of the key initiatives being proposed in this case to enable the Company to build for the future?

A. The proposals in this case allow the Company to begin delivering the future outlined in the EDIIP and IRP so that the benefits of those plans may be realized. As described below and discussed in greater detail in the supporting Company witnesses' testimonies, the Company is increasing its investment in demand-side and renewable resources and taking steps to prepare for a future with more modular, distributed generation.

1. <u>D.E. Karn Site</u>

Consistent with the Company's IRP, Consumers Energy is on track to retire its D.E. Karn ("Karn") Units 1 and 2 coal units in May 2023, which will be backfilled with a mixture of EWR, CVR, DR, and solar energy. As described in Company witness Scott A. Hugo's testimony, until those units are retired the Company must continue to maintain and operate those units in a safe, reliable manner and abide by any applicable laws and/or regulations. To ensure that the Company can retain the necessary qualified employees to maintain and operate Karn Units 1 and 2 through their retirement date, the Company developed and began implementation of a retention and separation plan. In the test year, the Company is including $12.9 million in capital investment and $38.3 million in O&M related to decoupling Karn Units 1 and 2 from Karn Units 3 and 4, continued environmental compliance, as well as other projects necessary to continue the safe operation of Karn Units 1 and 2 up until their retirement. As discussed by Company witness Harry, the Company proposes to defer 2020-2023 Karn Units 1 and 2 retention and separation costs in a regulatory asset to be amortized and recovered beginning the year after costs are incurred through 2039 (the estimated remaining life of the Company's remaining coal plants). Consumers Energy estimates that the total O&M costs deferred will be $27.4 million. Company witness Heidi J. Myers notes that approving the deferral of these costs would reduce the revenue requirement in this case by $5.5 million.

2. Grid Modernization

Grid Modernization includes core grid infrastructure improvements and investments that facilitate the incorporation of new technologies and applications into the electric system to increase reliability, allow optimization of the delivery system, and integration of more diverse energy resources. The Company proposes to invest $69.6 million in Grid Modernization which is included in the $722.7 million test year capital spend sponsored by Company witness Blumenstock. As described in greater detail by Company witness Blumenstock, some specific grid modernization improvements include upgrading existing LVD Substations with Distribution Supervisory Control and Data Acquisition, adding additional distribution automation, grid analytics, and deployment of an Advanced Distribution Management System. Investment in grid modernization is important for system reliability today and plays an even larger role in the future where the Company will rely on cleaner, more modular, and distributed energy resources. New system capabilities that will be enabled through investment in grid modernization include Fault Location, Isolation, and Service Restoration ("FLISR"),[7]Volt-VAR Optimization ("VVO"),[8] and CVR.

3. Demand Response

DR programs play a pivotal role in the Company's transition to a clean and lean energy future. In its September 15, 2017 Order in Case No. U-18369, the Commission established a process of review and approval of DR costs. As laid out in that Order, DR capital costs are to be reviewed and pre-approved in the Company's IRP proceeding while DR O&M is reviewed and approved in a general rate case proceeding. DR-related capital and O&M is then recovered in the base rates that get set in the Company's general rate case. Any differences between actual and recovered capital and O&M costs are to be reconciled in a separate reconciliation proceeding. In this case, the Company is not proposing any major changes to the approved DR regulatory framework. However, in an effort to simplify and streamline the DR process, as described in the testimony of Company witness Steven Q. McLean, the Company proposes to include a DR surcharge as part of the DR reconciliation process. The surcharge will allow for a refund in the event of an annual underspend, recovery of any prudent spending above rates, and collection of any future financial incentives for proven DR performance.

4. Conservation Voltage Reduction

The Company's CVR Program, enabled by Grid Modernization investments, optimizes voltage at circuits across the system to reduce energy demand without requiring

[7] FLISR, described in greater detail by Company witness Blumenstock, allows the Company to quickly and automatically restore power to as many customers as possible, without requiring intervention by Company operators or crews.
[8] VVO, described in greater detail by Company witness Blumenstock, enables coordinated control of voltage regulators and switched capacitor banks to reduce system losses and eliminate waste.

active participation or behind-the-meter investment by customers. CVR is a clean, cost effective way for the Company to meet its future energy needs and, for that reason, was identified by the Company as a key resource in its IRP. The CVR Program encourages system voltage optimization, carbon reduction, and is forecasted to reduce annual system energy use by 256,733 MWh and reduce annual capacity by 111 MW by 2028. As described by Company witness Michael J. Delaney, while the CVR Program offers a high value proposition for customers, this value does not translate to the Company's shareholders. Accordingly, the Company is proposing a shared savings incentive mechanism that connects broader customer and societal values with shareholder value creation. A shared savings incentive will encourage utility innovation by creating opportunities for experimentation with new programs and technologies that have the potential to create significant customer, environmental, and societal value. The CVR incentive, if approved, would be collected through a surcharge recovery mechanism with an annual reconciliation process, as described in more detail by Company witness Myers.

5. <u>Financial Compensation Mechanism</u>

In Consumers Energy's IRP, the Company received approval of a Financial Compensation Mechanism ("FCM") on new Power Purchase Agreements ("PPAs") approved by the Commission on or after January 1, 2019. The methodology for recovery of the FCM was not determined in the IRP and was directed to be determined in the Company's next rate case. Company witness Myers describes the Company's proposed recovery methodology while Company witness Keith G. Troyer calculates the FCM amount for the years 2019-2021. Company witness Harry also discusses the appropriate accounting treatment of the FCM.

6. Distributed Generation

In Case No. U-18383, the Commission directed the Company to file a Distributed Generation ("DG") tariff in this case based on an Inflow/Outflow billing mechanism. Under this design, customers with solar or wind generation are billed their normal rates for all power taken from the grid (Inflow) and provided a production credit for all excess generated power put back on the grid (Outflow). The Inflow/Outflow method is superior to the Company's existing net metering program in that it better reflects the benefits and costs associated with DG. As described in greater detail by Company witness Hubert W. Miller III, the Company recommends the Commission approve its proposal to replace the current net metering tariff with the new DG Inflow/Outflow tariff filed in this case.

Q. Are there any other investments required to enable the Company to build for the future?

A. Yes. The Company needs to ensure that the IT systems and capabilities are in place to support a future where energy generation is increasingly distributed and complex. The Company will rely heavily on the use of new technology to support the devices, communications, and analytics that enable grid modernization and VVO, CVR, and FLISR. Technology also plays a key role in supporting and enabling the growth of EWR, DR, and an increasing reliance on DER. These programs and initiatives are increasing the complexity of the Company's technology needs which increase the operating expense needed to maintain and operate them securely and reliably. Limiting recovery of IT operational O&M to the historic five-year average would negatively impact the Company's ability to invest in and operate this important technology.

C. Key Driver 3: Other

Q. Are there any other Company proposals in this case you wish to address?

A. Yes. While many of the key drivers in this case can be framed under the Company's efforts to excel at the basics and build for the future, there are other prominent proposals included in this case that bear mentioning.

1. Long-Term Industrial Load Rate

As described in the testimony of Company witness Michael P. Kelly, the Company seeks Commission approval of a Long-Term Industrial Load Rate ("LTILR") – also known as the Long-Term Industrial Load Retention Rate ("LTILRR") – and the proposed contract between the Company and Hemlock Semiconductor Operations LLC ("HSC"). The LTILR and HSC contract are in accordance with the 2018 PA 348 ("Act 348") which allows for large industrial companies that meet certain criteria to qualify for a tariff rate based on the cost of a designated generation source. The LTILR is intended to provide a competitive pricing option to retain qualifying high load factor customers to help ensure they continue to contribute to the recovery of fixed costs of a system that was built to serve their needs. Act 348 requires, among other things, that the Company demonstrate that the LTILR provides a net benefit to the utility's customers. As discussed in greater detail by Company witness Miller, customers will realize net benefit from the contract with HSC; the difference between the incremental cost to serve and contribution results in a positive net benefit of $153.5 million over the expected life of the tariff.

2. Electric Rate Case Deferral

In the Company's last electric rate case (Case No. U-20134) the Commission approved a settlement agreement that allowed for deferred accounting for the return on, return of, and property taxes associated with actual 2019 capital spending above $94 million for the New Business Program, $87 million for the Reactive Demand Failures Program, and $24 million for the Asset Relocation Program. The Company exceeded all three of the above distribution programs in 2019. Company witness Myers provides a calculation of the electric rate case deferral amount and a proposal of how the deferral be collected from customers. Company witness Harry also discusses how the Company will handle this deferred accounting going forward.

3. Pension Contribution

Customers stand to benefit from the Company's January 2020 $531 million pension contribution which fully funds its pension obligation and reduces pension expense in the test year.

III. CUSTOMER IMPACT

Q. Please summarize the impact of the Company's proposals on the revenue request in this case.

A. The Company requests rate relief in the amount of $244.4 million, which includes the following drivers:

Infrastructure Investment	$180.5 million
Cost of Capital	$27.3 million
Operating Expenses	$108.2 million
Sales/Revenue	($35.9) million
Tax Credit and Jobs Act ("TCJA") Amortization	($35.7) million
Total	$244.4 million

The requested rate relief will fund critical investments that enhance safety and reliability and enable the Company to take steps toward transitioning to a cleaner more efficient energy system. The majority of the increase in this case is in investments that target system reliability; of the $244.4 million request in this case, over 80% is related to investment in HVD and LVD infrastructure improvements, forestry/line clearing and service restoration.

Q. Please quantify the average overall rate increase if the Commission authorizes the rate relief requested.

A. Consumers Energy's $244.4 million rate request equates to an overall average increase of 5.9%.

Q. How do you expect this request to impact the typical residential customer's bill?

A. Consumers Energy's average residential bill has been consistently below the national average from 2012 through 2019 and is projected to remain below the national average even after including the impact of the proposed increase in this case. The Company expects that the average residential electric customer will pay less than $4.00 a day for electricity during 2021.

The Company understands that this increase will challenge some customers more than others. For this reason, Consumers Energy makes a range of assistance options available, including the Consumers Affordable Resource for Energy Program ("CARE"), a Residential Income Assistance credit, and a new Low-Income Assistance Credit ("LIAC") for qualifying customers, as described in the testimony of Company witness McLean. The Company and its employees are also generous contributors to community-based groups including the United Way, the Salvation Army, and many other local service organizations. Consumers Energy strives to keep its requested increase as low as reasonable while continuing to improve service and reliability.

IV. 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:

- **Richard T. Blumenstock** will address the function and state of the Company's HVD and LVD systems and the Company's proposed investment and O&M spending in those systems;
- **Douglas E. Detterman** will address the Company's workforce and resource needs and the Company's workforce development plan that will allow the Company to make the investment in the HVD and LVD systems outlined in this case;
- **Chris A. Shellberg** provides an overview of the Company's line clearing program and the Company's proposal to increase spending to achieve an effective seven-year LVD line clearing cycle;
- **Brenda L. Houtz** supports the Company's storm restoration costs. Company witness Houtz also addresses the Company's Unified Control Center project and costs;
- **Scott A. Hugo** provides an overview of the Company's current generation assets, test year periodic outage plans, generation unit availability, and projected solar investment pursuant to the Company's approved IRP. Company witness Hugo also supports generation capital expenditures and O&M expense including Karn Units 1 and 2 retention and separation expense;
- **Keith G. Troyer** provides support for the test year PSCR costs, the Company's State Reliability Mechanism, the transmission cost analysis and the recovery of costs associated with the FCM and solar solicitations;
- **Heather A. Breining** provides an overview of the environmental regulations with which the Company's electric generating fleet must comply, the cost of compliance with those regulations, as well as the timing and the justification for the investments made to ensure regulatory compliance;
- **Steven Q. McLean** describes the work done by the Company's Customer Experience & Operations area and how this work benefits customers. Company witness McLean also supports the test year capital investment and O&M expense associated with Customer Experience and supports the Company's DR programs and LIAC;

- **Jeffrey D. Tolonen** supports the IT and Security Department's test year O&M expense and capital investment which is needed to maintain existing IT/Security systems, enable new programs, and support the Company's proposals in this case;

- **Kyle P. Jones** describes the function and needs of the Company's fleet services and supports the test year fleet investment;

- **LaTina D. Saba** describes the function and needs of the Company's facilities and supports the test year facilities investment and O&M;

- **Michael J. Delaney** provides support for the Company's proposal to establish an incentive as a part of its CVR Program;

- **Daniel L. Harry** provides support for the Company's proposed accounting treatment of certain costs in this case and the use of regulatory assets and liabilities;

- **Lora B. Christopher** provides support for the Company's costs related to retirement, healthcare, life insurance, and long-term disability insurance for employees and retirees;

- **Amy M. Conrad** provides support for the recovery of costs related to the Company's annual Employee Incentive Compensation Program ("EICP");

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

- **Sarah R. Nielsen** supports the Company's electric vehicle initiatives including a new pilot program – PowerMIFleet – that supports customers seeking to electrify their fleet vehicles;

- **Karen M. Gaston** supports the Company's Corporate Services capital and O&M expense which includes the Company's injuries and damage as well as uncollectible expense;

- **Eugène M.J.A. Breuring** supports the Company's electric revenues, deliveries, generation requirements, and peak demand in the test year;

- **Brian J. VanBlarcum** supports the Company's real and personal property taxes as well as the excess deferred federal income taxes being returned to electric customers as a result of the TCJA;

- **Heidi J. Myers** presents the historic and test year revenue deficiency in compliance with the MPSC's filing requirements. In addition, Ms. Myers supports recovery and recovery mechanisms associated with other Company proposals in the case;

- **Todd A. Wehner** supports the Company's proposed Return on Equity that should be used in computing the overall Rate of Return ("ROR");
- **Marc R. Bleckman** supports the Company's proposed capital structure and cost of capital which should be used in computing the overall ROR;
- **Hubert W. Miller III** sponsors the Company's proposed rate design in addition to the Company's DG Tariff and calculation of the net benefit associated with the LTILRR;
- **Michael P. Kelly** sponsors the Company's proposed contract with HSC, including a calculation of revenues in the test year, and provides support for the establishment of the LTILRR;
- **Josnelly C**. **Aponte** sponsors and provides support for the Company's Cost-of-Service Study; and
- **Rachel L. Barnes** sponsors the Company's electric tariffs that have been updated to reflect the Company's proposals in this case.

In addition to the above, **Phillip M. Rausch** is providing direct testimony as a joint witness for HSC and Consumers Energy in support of Consumers Energy's proposed LTILRR and associated LTILRR contract between Consumers Energy and HSC.

Q. Does this complete your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697

DIRECT TESTIMONY

OF

JOSNELLY C. APONTE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Josnelly C. Aponte, and my address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

A. I am a Principal Rate Analyst-Lead in the Rate Analysis and Administration Section of the Rates and Regulation Department.

Q. Please state your educational background and work experience.

A. I graduated with a Bachelor of Accounting Degree in 1996 from Andres Bello University in Venezuela. I also received a Master of Business Administration Degree from Spring Arbor University in 2009. In addition, I have attended a number of utility ratemaking courses, regulatory studies programs and forums, electric load research courses, and electric and gas rate courses.

From October 1999 through February 2006, I was employed as a Controller by Seneca, a Venezuelan subsidiary of CMS Enterprises. My responsibilities included: (i) managing the finance function; (ii) overseeing the finance team; (iii) preparing budgets and forecasts; (iv) maintaining financial ledgers and accounting processes; (v) preparing monthly financial statements and all supporting information for the annual audit and tax returns in compliance with the Sarbanes-Oxley Act; and (vi) ad-hoc financial modeling and analyses.

I transferred to the CMS Enterprises' Accounting Department in Jackson, Michigan, in February 2006, to manage the reporting of the South American subsidiaries. In September 2007, I accepted a Senior Analyst position with Consumers Energy in the Corporate Forecasting area, where my primary responsibility was to maintain the financial property model used for budget and forecast reporting to the Board of Directors and investors. This model was also used for the calculation of the test year net plant, including construction work in progress and depreciation expense, included in rate case filings.

In March 2011, I accepted a position within the Distribution and Customer Operations Strategy team where I developed the strategic communication plans for field operations to improve customer service, and provided financial analysis for business cases, such as the expansion of gas distribution facilities. As a result, I became the gas Customer Attachment Program Administrator. In this role, I was responsible for evaluating, coordinating, and administering consistent policy and procedural information related to the extension of distribution gas facilities to connect new customers. I also provided periodic program updates to members of the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") and to Company management.

In July 2013, I joined the Rate Analysis and Administration Section where I am currently a Principal Rate Analyst-Lead. My responsibilities in this capacity include leading the development of load studies, cost-of-service studies, and associated research and analysis, in addition to responding to various internal and external inquiries regarding rate-related issues.

Q. Have you previously filed testimony with the MPSC?

A. Yes. I have filed testimony on behalf of the Company in the following cases:

Case No. U-17643	Gas General Rate Case, Cost-of-Service;
Case No. U-17825	Electric residual balance reconciliation, Rate Design;
Case No. U-17771	Energy Optimization Plan, Rate Design;
Case No. U-17882	Gas General Rate Case, Cost of Service;
Case No. U-17990	Electric General Rate Case, Cost of Service;
Case No. U-18010	Amendments to Gas Transportation contracts, Cost of Service, Rate Design, and Tariff;
Case No. U-18025	Energy Optimization Reconciliation, Rate Design;
Case No. U-18239	State Reliability Mechanism, Cost of Service;
Case No. U-18322	Electric General Rate Case, Cost of Service;
Case No. U-20134	Electric General Rate Case, Cost of Service;
Case No. U-20286	Determination of Electric Credit B, Cost of Service; and
Case No. U-20322	Gas Power Generation, Cost of Service, Rate Design, and Tariff.

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

A. The purpose of my testimony is to present the Company's electric cost-of-service studies for the forecasted fiscal year-end December 2021 ("test year") and sponsor any related proposals.

Q. Is the Company proposing any changes related to its cost-of-service studies?

A. Yes. I am sponsoring six Company proposals, which include changes related to: (i) the production capacity allocator; (ii) the distribution allocation for the General Service Self Generation Rate GSG-2; (iii) the treatment of capacity for interruptible load; (iv) the treatment of capacity for Energy Intensive Primary load; (v) further breakdown of the load profiles for General Service Primary Rates; and (vi) the determination of customer related costs.

Q. Are there any other items addressed in your testimony?

A. Yes. Consistent with the application of the Company's Notification of Annual Review of the State Reliability Mechanism ("SRM") Capacity Charge, filed on March 30, 2018 in Case No. U-18239, the Company is updating the SRM capacity charge for the test year. In addition, I am sponsoring the allocation of various surcharges and supporting the Company's compliance with certain items from the Settlement Agreement approved by the Commission on January 9, 2019 in MPSC Case No. U-20134.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring the following exhibits:

Exhibit A-16 (JCA-1)	Schedule F-1	Electric Cost-of-Service Study – Projected 12-Month Period Ending Dec 31, 2021 - Version 1;
Exhibit A-16 (JCA-2)	Schedule F-1.1	Electric Cost-of-Service Study – Projected 12-Month Period Ending Dec 31, 2021 - Version 2;
Exhibit A-17 (JCA-3)		Capacity Related Cost and Charge Calculation;
Exhibit A-18 (JCA-4)		Production Allocator Energy Weighting;
Exhibit A-19 (JCA-5)		Substation Ownership Credit;
Exhibit A-20 (JCA-6)		Allocation of Surcharges;
Exhibit A-21 (JCA-7)		Standby Study by the Brattle Group; and

Exhibit A-22 (JCA-8)	Electric Cost-of-Service Study – Projected 12-Month Period Ending Dec 31, 2021, Informational Only.

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

A. Yes, they were.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. COST OF SERVICE OVERVIEW

II. TEST YEAR ELECTRIC COST-OF-SERVICE STUDY

III. TEST YEAR ELECTRIC COSS- VERSION 1

IV. TEST YEAR ELECTRIC COSS - VERSION 2

V. SUMMARY OF IMPACTS OF COMPANY PROPOSALS

VI. SRM CAPACITY CHARGE CALCULATION

VII. SUBSTATION OWNERSHIP CREDIT CALCULATION

VIII. ALLOCATION OF SURCHARGES

IX. COMPLIANCE WITH SETTLEMENT AGREEMENT CASE NO. U-20134

I. <u>COST OF SERVICE OVERVIEW</u>

Q. What is a Cost-of-Service Study ("COSS") by rate class?

A. A COSS by rate class is a systematic functionalization, classification, and allocation of a utility's fixed and variable costs to serve. Each COSS filed in this case serves two purposes. First, the process of preparing the COSS identifies and separates costs associated with the utility's production and distribution of electricity into the jurisdictional electric rate classes. Secondly, the COSS is used to determine the relative contribution to jurisdictional earnings from each of the Company's jurisdictional electric rate classes.

Q. Please explain what is involved in performing a COSS.

A. A COSS compares how costs are incurred with how costs are recovered for a designated time period. The Company uses standard methods supported by the National Association of Regulatory Utility Commissioners ("NARUC"). First, the Company identifies and separates plant and expenses into specific categories based on the function that each cost is incurred to provide or support. Consumers Energy's functional cost categories are Production and Distribution. Second, the Company classifies the functionalized costs into demand, customer, and energy components according to the primary cost drivers. Finally, the Company allocates those costs to each customer class using a variety of factors that correlate to the identified cost drivers. Common allocation factors include energy use, demand, and number of customers, among others. When possible, individual costs that can be traced to a rate class are "specifically assigned" to that particular rate class. Non-specific cost items are allocated among the rate classes for whose benefit the costs were incurred.

Q. How does the Company present the results of its COSS?

A. The Company presents the results of its COSS in compliance with the Commission's Standard Filing Requirements that were approved in Case No. U-18238.

Q. Are the retail open access customers included in the Company's COSS?

A. Yes. The retail open access customers are included in the full-service rate class that they would be assigned to if they were on full-service tariffs, because distribution energy costs are the same for both retail open access and full-service customers.

II. TEST YEAR ELECTRIC COST-OF-SERVICE STUDY

Q. How many versions of the Electric COSS are you sponsoring?

Q. I am sponsoring two versions of the Electric COSS. The first version of the Test Year Electric COSS ("Test Year COSS – Version 1") conforms to the Commission's COSS decisions in Case No. U-18322, the Company's last general electric rate case approved via final order.[1] The second version of the Test Year Electric COSS ("Test Year COSS – Version 2") uses the Test Year COSS – Version 1 as its starting point and includes the Company proposals described later in my direct testimony. Both versions of the COSS rely on the methodologies described in this section to develop the allocation schedules.

Q. How did you develop the test year allocation schedules?

A. There are 18 distinct allocation input schedules developed for use in the Electric COSS. Each schedule was developed to allocate to each customer class its utilization of a particular part of the electrical system, which is the industry standard practice for developing allocation schedules. Nine schedules were based on energy at generation, two schedules were based on the demand that a class places on the various portions of the electrical system, and the remaining schedules were based on revenues, sales, or customer levels. The schedule numbers and the associated portion of the electrical system that they represent are shown on Exhibits A-16 (JCA-1), Schedule F-1, and A-16 (JCA-2), Schedule F-1.1, pages 10 through 12. Schedules 100, 101, 102, 103, 104, 105, 106, 107, and 108 are based on the energy used by customers at different time periods, seasons, or in total. Coincident Peak ("CP") demands were the basis for schedules 120

[1] The Company filed a general electric rate case after Case No. 18322 (Case No. U-20134) which resulted in a settlement agreement.

and 121, while class peak demands were used to develop schedules 122 and 127. Total revenue, billed sales, number of customers, and customers weighted on average meter expense were the basis for schedules 143, 150, 151, 160, and 170, respectively.

Allocation schedules were developed using test year rate class revenue, sales and customer data, Company records, load research samples, and quantitative methods to determine the extent (expressed as a percentage) that each customer class uses the various portions of the electrical system. The percentages determined in the allocation schedules were used to calculate rate class cost responsibility in the COSS. Because all customer classes do not utilize the full distribution system to take delivery of electrical service, the allocation schedules were developed to assign only the portions of the system used by each customer class.

Q. How were the demand and energy allocation schedules developed?

A. The test year allocation schedules use a three-year average of historic energy use profiles (2016, 2017, and 2018) to develop an average test year profile for each class. Then, the loss factors sponsored by Company witness Richard T. Blumenstock are applied to the average test year profile to arrive at generation-level energy use. The average test year profile determines the demand and energy allocation schedules 100 through 127. Allocation schedules 100 through 108 were developed by taking the appropriate energy for each class and dividing it by the total of the energy for all classes to develop a percentage by class. The demand coincident to a peak (CP) and the class peak are divided by the sum of the demand for each class to develop the percentages in allocation schedules 120 through 127.

Q. How were the historic load profiles developed?

A. The Company utilizes an external consultant to develop an average load profile. The consultant uses load research software to extrapolate a total class profile based on the Company's meter data from each rate class. Load profiles for street lighting were assumed to follow daylight hours, and the profiles for unmetered usage were assumed to be a flat average use per hour.

Q. Were load profiles based on sample data or billing data?

A. Depending on the rate, either sample data or billing data was utilized to develop the different load profiles. Residential, Secondary Commercial, and Primary energy-only rates were all based on meter samples. Primary demand rates were based on all available actual billing data.

Q. Do the allocation schedules and load profiles used by the Company follow established industry COSS principles and methods?

A. Yes. The development of the schedules and load profiles follow industry recognized and accepted load research principles supported by the Edison Electric Institute and the Association of Edison Illuminating Companies ("AEIC"). The methods used also conform to nationally recognized standards for developing allocation schedules. Furthermore, the software used to develop the load profiles for the Company's Load Study is documented and has been taught at the biennial AEIC Advanced Applications in Load Research workshop. In addition, the Commission has consistently relied on these principles and methods in the past.

Q. How were the other allocation schedules developed?

A. Allocation schedules 143, 150, 151, 160, and 170 were developed using data supplied by Company witness Eugene M. Breuring and Company witness Hubert W. Miller III. More specifically, the Company used revenues, sales, or customers associated with each class and divided by the total revenues, sales, or customers to develop the percentages used for allocating costs.

Q. How are the revenues of the Long-Term Industrial Load Retention Rate ("LTILRR") treated in the Electric COSS?

A. The revenues of the LTILRR are reported by Company witnesses Breuring and Heidi J. Myers as Miscellaneous Revenue/Other Electric Revenue. Therefore, they are included under the Non-Power Supply Cost Recovery (PSCR) Rate Revenue Credits section of the COSS (Exhibits A-16 (JCA-1), Schedule F-1, and A-16 (JCA-2), Schedule F-1.1, page 28). Using the breakdown of the revenue provided by Company witness Michael P. Kelly, the Company assigned the appropriate allocator to each line item of the LTILRR contract revenues, as follows:

Description	Allocator
Capacity	220
Energy On-Peak Summer	103
Energy Off-Peak Summer	104
Energy On-Peak Non-Summer	105
Energy Off-Peak Non-Summer	106
Transmission	120
Delivery	390

III. TEST YEAR ELECTRIC COSS – VERSION 1

Q. Please describe the allocations approved by the Commission in Case No. U-18322 that were used to develop the Test Year Electric COSS – Version 1.

A. Production capacity is allocated using an allocator weighted 75% on 4 CPs for the demand component, 0% on on-peak energy, and 25% on total energy ("4 CP 75/0/25"). Production energy expenses are allocated based on energy at generation for the associated time periods and seasons. Transmission expense is allocated by means of 100% demand on 12 CPs ("12 CP 100"). Distribution plant and expense are primarily allocated on demands by class at the appropriate voltage level.[2] General, common, and intangible items are predominantly allocated based on labor. Working capital is allocated based on revenues, plant in service, and labor. Property tax is allocated in the same manner as the associated plant and income tax is allocated – based on pretax net operating income.

[2] Meter facilities and services are assigned using allocators based on the number of customers.

Q. Please describe Exhibit A-16 (JCA-1), Schedule F-1.

A. Exhibit A-16 (JCA-1), Schedule F-1, is a 39-page exhibit that summarizes the Test Year COSS – Version 1, which reflects the test year proposals as presented by other Company witnesses.

Q. How is Exhibit A-16 (JCA-1), Schedule F-1, organized?

A. Across the top of page 1 are the Company's rate classes to which the total cost to serve is allocated. Total Company electric information for the test year is found in column (c), while the MPSC jurisdictional information is shown in column (d), and non-jurisdictional information is reported in column (j). Columns (e) through (i) show the distribution of the MPSC jurisdictional cost to serve each of the Company's rate classes. The same information by rate schedule is found on pages 2 and 3. Pages 1 through 3 show rate base and net operating income in summary and by rate schedule. Line 20, pages 1 through 3, displays the revenue deficiency (sufficiency). Lines 24 through 28 functionalize the revenue requirement reflected on line 21. Pages 4 through 6 of the exhibit shows the development of total rate base, pages 7 through 9 detail the total electric Operating and Maintenance ("O&M") expense, and pages 10 through 15 list the allocation schedules used in the Test Year COSS – Version 1.

Q. What is shown on pages 16 through 39 of Exhibit A-16 (JCA-1), Schedule F-1?

A. Pages 16 through 39 of Exhibit A-16 (JCA-1), Schedule F-1, show the details of all the line items needed to calculate the Proposed Rate Design Revenue and their individual allocations, as required by the Schedule F-1 template included in the Commission's Standard Filing Requirements that were approved in Case No. U-18238.

Q. Is the Test Year COSS – Version 1 used for rate design purposes?

A. No. The Test Year COSS – Version 1 is used as a base for comparison purposes with the version of the COSS the Company is proposing for rate design, which I will address next.

IV. TEST YEAR ELECTRIC COSS – VERSION 2

Q. Please describe Exhibit A-16 (JCA-2), Schedule F-1.1.

A. Exhibit A-16 (JCA-2), Schedule F-1.1, is a 39-page exhibit that summarizes the Test Year COSS – Version 2. This study uses the Test Year COSS – Version 1 as its starting point and includes the following: (i) an updated production capacity allocator; (ii) a change in the distribution allocation for the General Service Self Generation Rate GSG-2; (iii) a change in the treatment for the capacity associated to interruptible load; (iv) a change in the treatment for the capacity associated with Energy Intensive Primary load; (v) a further breakdown of the load profiles for General Service Primary Rates; and (vi) an update to the calculation of customer related costs. The 39 pages of Exhibit A-16 (JCA-2), Schedule F-1.1, are organized in the same manner as the 39 pages of Exhibit A-16 (JCA-1), Schedule F-1.

A. Production Capacity Allocator Update

Q. What is Consumers Energy's current Commission-approved production capacity allocation methodology?

A. As explained earlier in my direct testimony, the Company uses a 4 CP 75/0/25 methodology, as previously approved by the Commission, to allocate production capacity costs. This method incorporates two measurements: (i) the average of class demand during the four demand peaking months, which is weighted at 75%; and (ii) class total energy usage, which is weighted at 25%. This method and its associated weighting were reviewed and approved by the Commission in Case No. U-17689 and later included in the Michigan Public Act 341 in 2016 (MCL 460.11(1)). Since then, the MPSC has consistently relied on this method and weighting to allocate production costs to customers. MCL 460.11(1), however, also states that "[t]he [C]ommission may modify this [75/0/25] method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service." Therefore, the Commission may modify the 4CP 75/0/25 allocation if compelling evidence is provided that an alternative methodology more accurately reflects the cost of service.

Q. Has the Company analyzed different production capacity allocation methodologies?

A. Yes. The Company analyzed three different energy weighting methods, as recognized by the NARUC Electric Utility Cost Allocation Manual (January 1992), for allocating production costs: (i) the Judgmental or Discretionary Energy Weighting method, which includes the current approved 75/0/25 weighting; (ii) the Average and Excess method; and (iii) the Equivalent Peaker methods. Each of these methods are briefly explained below:

(a) Judgmental or Discretionary Energy Weighting ("DEW") method -

The DEW method is a flexible method that doesn't prescribe a theory of how energy should be weighted in the production allocator. Rather, it allows for analyst discretion on how energy and demand contribute to production capacity costs;

(b) Average and Excess ("A&E") method -

The A&E cost allocation method involves developing two components that are combined using a weighted average. The first component, referred to as the average component (or "average demand"), represents each rate class's average hourly energy consumption throughout the test year. The second component, referred to as the excess component (or "excess demand"), represents each rate class's average contribution to the utility's overall system peak demand. The average component is weighted by the utility's overall system load factor, while the excess component is weighted by the inverse of the system load factor (i.e., 1 minus the system load factor).[3] The average demand component is an energy allocator to apportion the utility's generating capacity that would be needed if all customers used energy at a constant 100% load factor, and the excess demand component represents the proportion of the difference between the sum of all classes' chosen CPs and the system average demand; and

(c) The Equivalent Peaker ("EP") methods -

According to the NARUC Manual, EP methods assume that generation planning considers peak demand loads and energy loads separately when determining the need for additional capacity and the most cost-effective type of capacity to be added. These methods are based on a premise that (i) increases in peak demand require the addition of peaking capacity only, and (ii) more expensive intermediate base load units are incurred to serve energy. EP methods then assign peak capacity costs as demand related, while the difference between the utility's total cost of production plant and the cost of the peak capacity (intermediate and base load) is classified as energy related (NARUC Manual, pages 52 and 53).

Q. Which method is the Company proposing that the Commission adopt in this case?

A. As noted above, and described later in my direct testimony, the Commission relied on a DEW method that resulted in a 75/0/25 weighting that continues to be applied to utilities in Michigan. While Consumers Energy believes that the 100/0/0 weighting or 100% demand best reflects how its production capacity costs should be allocated, Consumers Energy is proposing to maintain the DEW method approved by the Commission with an update from 75/0/25 to 89/0/11. Moreover, EP methods are inappropriate to allocate the Company's production capacity costs as explained later in my direct testimony.

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[3] The formula is as follows:

$A\&E = (AD\% \times LF\%) + [ED\% \times (1-LF)]$

Where:

AD% = each class' share of Average Demand (or energy usage)

ED% = each class' share of Excess Demand, which is the difference between chosen peak demand and Average Demand

LF% = System Load Factor

Q. Why is the Company proposing to update the production capacity allocator to 4CP 89/0/11?

A. In the final order for Case No. U-17688, the Commission justified the 25% energy weighting of the capacity allocator with an analysis prepared by Staff that relied on the Company's Generating Plant Statistics for the year 2013. This analysis is over seven years old; more recent data on the Company's generation plant, the makeup of which has changed over that time period, is available. In addition, some modifications to the assumptions about how plants serve base load would better reflect how the Company's current generating plants operate.

Q. How did the Company calculate the update of the production allocator energy weighting to 11%?

A. Exhibit A-18 (JCA-4), Production Allocator Energy Weighting, shows the calculation of the percent that should be allocated on energy, using the same type of data Staff used to support the 25% energy weighting, updated for the last three historic years (2016, 2017, and 2018). The Company calculated the relationship between the cost associated with base load generation over the total cost of the Company's plants (Exhibit A-18 (JCA-4), line 44) and multiplied this percentage by the minimum load needed to serve all customers in each of those years (Exhibit A-18 (JCA-4), line 47). The result is the percent of capacity costs to be allocated on energy (3-year average of 11%; Exhibit A-18 (JCA-4), line 48).

Q. Did the Company follow the same analysis used by the Commission in Case No. U-17688 to support the energy weighting?

A. Yes, except that the Company (i) updated the calculation with the most recent historic data available, (ii) applied the appropriate allowance when calculating the minimum load produced by coal units, and (iii) excluded hydro plants from the calculation of the base load.

Q. Please explain why the Company made these modifications.

A. The Company's investment in generation has evolved in the last few years; the Company has reduced its dependence on coal and increased its reliance on renewable energy resources and demand response ("DR") programs. As the Company implements its Integrated Resource Plan ("IRP"), approved by the Commission in June 2019 (Case No. U-20165), the Company's generation fleet will continue to evolve. Utilizing more recent historic data better reflects this position.

In addition to updating the calculation with more recent data, the Company is proposing a revision to the assumption that coal plants, and other generation that has historically been referred to as "base load" power plants, serves 100% of the minimum system load today. Coal plants do not necessarily meet 100% of the system base load; the Midcontinent Independent System Operator, Inc. ("MISO") decides which resources will clear the market, which could include resources other than coal. The minimum load that these coal units produce is the only portion that should be considered base load for the purpose of this calculation, as shown in Exhibit A-18 (JCA-4), column (b), lines 37 through 42.

Likewise, considering hydro units as base load is not appropriate because these units are subject to variability in renewable supply (i.e., availability of water) and cannot guarantee a minimum supply throughout the year.

Q. How does the Company fulfill the rest of the system minimum load requirements if it does not use 100% of the capacity of its coal plants first?

A. MISO decides which units will be used in the energy markets based on what clears in those markets - in other words, MISO commits the lowest cost generators based on the market needs. During traditional base load hours, other units may be cheaper and will be dispatched before coal plants operate above their minimum. Considering that MISO assigns the value to the energy that will be needed based on the most expensive resource that allows for the energy and operating reserve markets to clear, customers creating the peaks should be responsible for those higher costs. This contribution is captured by decreasing the energy weighting of the production allocator from 25% to 11%. The Company submits that this update is necessary to better reflect the costs-to-serve for production.

Q. With the updates to the DEW calculation proposed by the Company, are there any remaining flaws or concerns using the DEW method to allocate production costs?

A. Yes. While the changes proposed by the Company decrease the energy weighting of the production allocator, there are some methodological flaws with the DEW method. Adding an energy component of any magnitude to the capacity allocator does not reflect how MISO operates. MISO has established the existence of two separate and distinct markets: one for capacity and one for energy. Each of them is planned and operated independently from one another; therefore, the use of an energy component when determining how capacity costs are allocated is inconsistent with this notion. In addition, as described in the MPSC's final order in Case No. U-17688, page 16, the DEW method generalizes the customers' energy usage by only taking into consideration the following: (i) the minimum energy usage in an hour; (ii) the percentage of base load energy out of the total energy for the year; (iii) the portion that base load energy represents from the maximum capacity needed for the year; and (iv) the portion of base load costs from the total cost of all generating units. While these four components of the allocator identify base load usage and related costs, they do not identify how efficient customer classes are in using energy and the burden that each class imposes on the system because of it. In other words, not taking into consideration each class's load factor[4] results in a less accurate matching of costs to the appropriate cost causers.

Q. Does the A&E address these issues?

A. Yes. While allocating costs using 100% demands is ideal, as explained earlier, the A&E method is a second best alternative as it takes into consideration each class's load factor. Load factors are an important consideration when choosing a production capacity allocator because they convey a unique insight into which rate classes are causing the loads being imposed on the system and which rate classes contribute more to peak production plant. To serve the low load factor peaks, generation units are sitting idle for long periods of time and, as a result, are imposing higher costs on the system. Serving high load factor customer peaks is more efficient; therefore, the cost-causation principle is met when customers with high load factors are allocated costs based on average

[4] Load factor is the ratio of the average demand over a period of time and the maximum demand that occurred during that same period. Load factors are lower for customers with significant variation between their demands and their energy usage. Customers with high load factors have less variation between demand and energy usage, meaning that energy usage is relatively constant.

demand, while those with peak demands much higher than their average demand are allocated additional costs based on their excess demand. The consequence of serving their load during high-peak and even critical-peak times is that costs are higher.

Q. If using 100% demands or the A&E method is superior, why is the Company proposing adoption of the DEW 89/0/11 allocation of production capacity costs?

A. In Case No. U-17689, the Commission reviewed the current DEW method and deemed it appropriate. As noted earlier in my testimony, this method was later included in Public Act 341. While the Company believes that using 100% demands or the A&E method is superior, the Commission has adopted the DEW method. Therefore, the Company is only asking that the Commission approve certain revisions to the existing DEW method that better reflect the Company's capacity cost allocation.

Q. Why did the Company conclude that EP methods are inappropriate to allocate production capacity costs?

A. There are two fundamental flaws that make EP methods inappropriate to allocate the Company's production capacity costs. First, EP methods rely on concepts that predate the creation of MISO, such as the assumption that the Company adds capacity with a short-term view of incremental demands and focuses on choices such as base, intermediate, and peak demands. This is not how the Company plans for capacity. The Company uses the IRP, an integrated system planning method reviewed and evaluated at length in the Company's Commission-approved Case No. U-20165, which does not separately plan and build capacity that focuses on simple choices between base, intermediate, and peaker units. The Company submits its available capacity to MISO, which is based on the IRP, and it is MISO who decides which resources will be used to meet the annual Planning Reserve Margin ("PRM") and determine the value of each MW (Zonal Resource Credit). Second, EP methods penalize high load factor customers by allocating to them a higher portion of the capital costs but ignoring the effects of fuel savings. For these reasons, EP methods are not only inappropriate but also irrelevant.

Q. Are there any additional opportunities to improve the current production allocator besides the further reduction or elimination of the energy weighting?

A. Yes. In order to fully reflect how capacity is planned and administered by MISO, the Commission could consider that the PRM is determined using a single peak in a year (1 CP). Therefore, using the current 4 CP as part of the capacity allocator does not fully reflect how capacity is determined and valued. However, the Company is not making a proposal to change the 4 CP portion of the allocator in this proceeding.

B. General Service Self Generation Rate GSG-2 Distribution Allocation

Q. What is the Company's proposal regarding the General Service Self Generation Rate GSG-2 distribution allocation?

A. Based on the stand by analysis discussed in section IX of my direct testimony, the Company determined that the current allocation of distribution costs based on historic class peak does not appropriately reflect the investments in the distribution assets that are ready to serve stand by customers. Therefore, the Company is proposing to utilize the contracted demand of GSG-2 customers, adjusted by a coincidence factor, in place of the average historic class peak, which is described in Exhibit A-21 (JCA-7), Standby Study by the Brattle Group ("Brattle Group"), page 8. For the Test Year COSS – Version 2, the

Company used the coincidence factor of 45%[5], which was calculated using 2018 historic data, considering that the peak of total customer demand for this group of customers increased more than 900% from 2016 to 2018.

C. Interruptible Load Capacity Treatment

Q. Please explain the Company's proposal regarding the treatment of interruptible load in the COSS?

A. In the Test Year COSS – Version 1, the Company allocates capacity costs to interruptible load, which then would have to be adjusted/removed in rate design because the Company does not plan for, or purchase capacity for, interruptible customers. The Company is proposing to make this adjustment in the Test Year COSS – Version 2 by removing the interruptible load from the calculation of the production capacity allocator for Rates GP and GPD. This treatment is consistent with the recommendations of James Bonbright et al., "Principles of Public Utility Rates" (1988), page 502:

> Interruptible service has been used by both gas and electric companies for peak shaving. The costs cannot be accurately determined because it is a byproduct resulting from generating and bulk transmission facilities built and operated for firm service (see Nissel, 1983). As a result, only the customer cost (e.g., customer- connected spur lines and substations) and energy cost (e.g., fuel and incremental maintenance costs) actually incurred and no capacity pricing cost should be included in pricing interruptible service.

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[5] Peak of Total Customer Demand (52,316 kW) ÷ Sum of Individual Customer Peaks (116,232 kW) = 45%

D. Energy Intensive Primary Load Capacity Treatment

Q. Please explain the Company's proposal regarding the treatment of the Energy Intensive Primary ("EIP") load in the COSS?

A. Similar to interruptible load, the Company does not plan for, or purchase capacity for, EIP customers. However, in the Test Year COSS – Version 1, the Company reduces the 12 CP demands associated with the EIP test year profile which not only reduces capacity costs but also reduces the allocation of transmission and distribution costs. In the past, adjustments to add back the transmission and distribution costs were made in rate design. The Company is proposing to amend the allocation of costs in the COSS by only removing EIP load from the production capacity allocator in the Test Year COSS – Version 2.

E. General Service Primary Rates Load Profile Breakdown

Q. Is the Company proposing any changes to its load profiles?

A. Yes. In the Test Year COSS – Version 1, the load for the General Service Primary Time-Of-Use Rate GPTU ("GPTU") is included with the Large General Service Primary Demand Rate GPD ("GPD"). In the Test Year COSS – Version 2, the Company is proposing to separate the GPTU load profile, and costs, from GPD. In addition, the Company is proposing to separate the load profile for the Voltage 3 customers using the interruptible provision ("GI") from the GPD load profile.

Q. What is the purpose of creating a separate GPTU load profile?

A. Rate GPTU is a relatively new rate such that there has been limited historical load data available prior to this proceeding. With the addition of the 2018 load study, the Company now has the three years of historical data it needs to calculate the test year load profile. Having a separate load profile for GPTU provides better insight into how GPTU customers use the system and cause costs, as well as provides for better guidance for rate design.

Q. What is the purpose of creating a separate GI load profile for Voltage 3 customers?

A. This treatment would make Voltage 3 customers consistent with customers on Voltage 1 and Voltage 2, which have separate load profiles for the interruptible provision. Having a separate load profile facilitates the appropriate assignment of line losses and the removal of interruptible load for purposes of assigning capacity costs proposed by the Company, as explained earlier in my testimony. The costs for these customers continue to be included in GPD Voltage 3, consistent with the treatment of the other two GPD voltages.

F. <u>Customer Related Costs</u>

Q. Is the Company proposing any changes to the calculation of customer related costs?

A. Yes. In the COSS, the Company currently calculates the share of distribution costs that are customer related, which is used by rate design to determine an appropriate customer charge, as follows:

Cost Category	Description
Return on Capital	Return (WACC) on Net Meter (370), Service (369) & Distribution Installation on Customer Premises (371) Plant
+ Depreciation Expense	Meter (370), Service (369) & Distribution Installation on Customer Premises (371) Depreciation Expense
+ Depreciation Expense	Customer portion of General, Common & Intangible (GC&I) Depreciation Expense*
+ Property Tax	Customer portion of GC&I Property Tax*
+ Distribution O&M	Customer Installation Expense (587)
+ Distribution O&M	Meters Maintenance Expense (597)
+ Customer Related & A&G	A&G- Production Related
+ Customer Related & A&G	Total Customer Accounts (901-905)
+ Customer Related & A&G	Total Customer Services (904-910)
+ Customer Related & A&G	Total Sales Expense (912)
+ Formula error	Incorrect formula reference
= Total Distribution Customer Costs	

*Customer portion determined by Customer Labor Ratio

The Company has identified three items that have been omitted from the current calculation, and the Company is proposing to update the study to include them.

Q. Please explain.

A. First, the current formula correctly includes the customer related portion of General, Common and Intangible ("GC&I") depreciation expense but omits the return on GC&I plant. Therefore, the Company is proposing to include a return on the customer related portion of GC&I Plant. Second, the current formula excludes meter operating expense (Federal Energy Regulatory Commission ("FERC") Account 586) but includes meter maintenance expense (FERC Account 597). In response, the Company is proposing to include meter operating expense in the calculation of customer related costs. Third, the current formula appears to inadvertently include production related Administrative & General ("A&G") expense instead of the customer related portion of A&G, which are broken out in the COSS model. Finally, the Company is proposing to remove an incorrect formula reference in the current calculation which does not have a material impact on the calculation but should be removed to provide an accurate calculation of customer related costs. An updated calculation of customer related distribution costs, which the Company is proposing to rely on, is shown below:

Cost Category	**Description**	**Jurisdictional Customer Costs (in millions)**	
		Current	**Proposed**
Return on Capital	Return (WACC) on Net Meter (370), Service (369) & Distribution Installation on Customer Premises (371) Plant	$65.0	$65.0
+ Depreciation Expense	Meter (370), Services (369) & Distribution Installation on Customer Premises (371) Depreciation Expense	71.3	71.3
+ Return on Capital	Return (WACC) on Customer portion of Net General, Common & Intangible (GC&I) Plant	-	4.3
+ Depreciation Expense	Customer portion of General, Common & Intangible (GC&I) Depreciation Expense*	12.3	12.0
+ Property Tax	Customer portion of GC&I Property Tax*	2.1	2.0
+ Distribution O&M	Customer Installation Expense (587)	5.5	5.5
+ Distribution O&M	Meter- Maintenance Expense (597)	4.9	4.9
+ Distribution O&M	Meter- Operating Expense (586)	-	1.4
+ Customer Related & A&G	A&G- Customer Related	-	16.4
+ Customer Related & A&G	Total Customer Accounts (901-905)	54.1	54.1
+ Customer Related & A&G	Total Customer Services (904-910)	16.8	16.8
+ Customer Related & A&G	Total Sales Expense (912)	0.4	0.4
+ Formula error	Incorrect formula reference	>0.1	-
= Total Distribution Customer Costs		**$232.2**	**$253.9**

*Customer portion determined by Customer Labor Ratio

Q. Does the Company proposal have an impact on how customer costs are allocated?

A. No. The proposal is limited to the classification of customers costs.

V. SUMMARY OF IMPACTS OF COMPANY PROPOSALS

Q. What is the impact of the Company's proposals included in the Test Year COSS – Version 2 on the different COSS' Rate Classes?

A. Figure 1 below shows the results of comparing the Proposed Rate Design Revenue to the Present Revenue for each of the versions of the COSS by customer class:

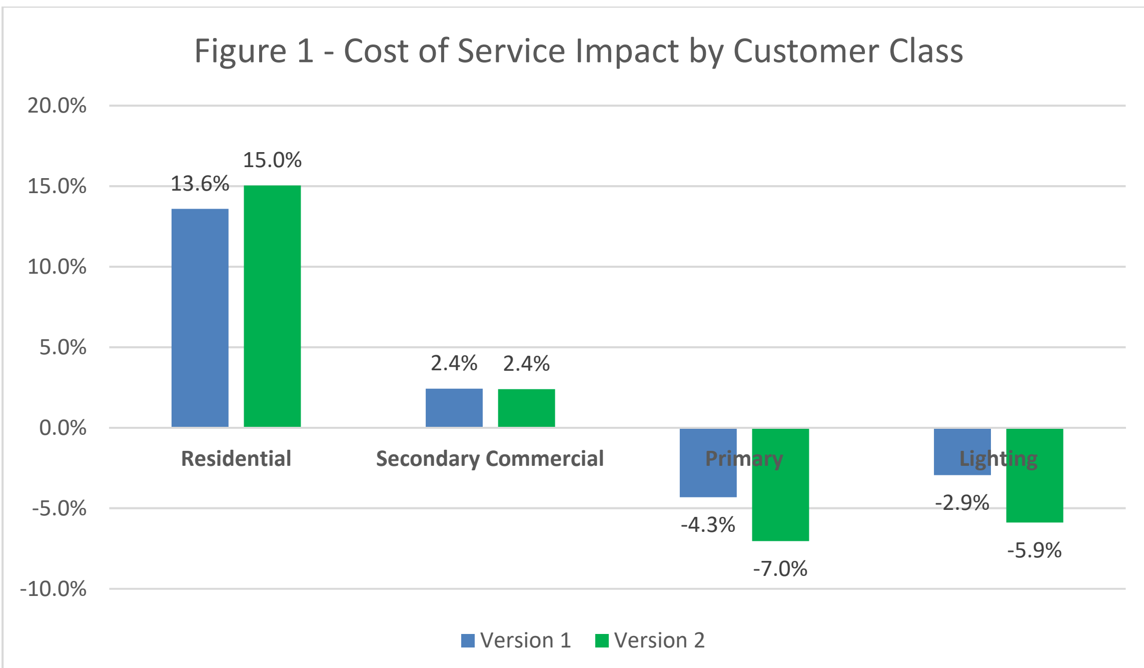

Figure 1 - Cost of Service Impact by Customer Class

As shown in the graph, the total of the Company's COSS proposals with the Test Year COSS – Version 2 would increase residential costs an additional 1.4% over present revenue and decrease secondary commercial, primary, and lighting costs >0.1%, 2.7%, and 3%, respectively, as compared to the Test Year COSS – Version 1.

VI. SRM CAPACITY CHARGE CALCULATION

Q. Please describe Exhibit A-17 **(JCA-3).**

A. Exhibit A-17 (JCA-3) shows the Capacity Related Cost and Charge Calculation related to the SRM for the test year, consistent with the application of the Company's Notification of Annual Review of the SRM Capacity Charge, filed on March 30, 2018 in Case No. U-18239. Lines 1 through 8 of Exhibit A-17 (JCA-3) are inputs from the total electric COSS, which determine what portion of the total Company production costs (line 1) are non-capacity related (lines 2 through 7) with the difference considered capacity related (line 9). The total capacity-related cost from line 9 is then offset by the projected revenue and associated fuel cost (line 10 sponsored by Company witness Keith G. Troyer and lines 11 through 13 supported by accounting records) to arrive at the net capacity cost (line 17). Company witness Troyer also provides the demand in MW used as the denominator to calculate the capacity charge of $447.71 MW/Day.

Q. How are the results of the production classification costs shown in Exhibit A-17 (JCA-3) used in this proceeding?

A. The total non-capacity related cost, the total revenue less fuel cost, and the net capacity cost from Exhibit A-17 (JCA-3), found in lines 8, 16, and 17, are shown in both versions of the COSS described in my direct testimony, specifically in Exhibits A-16 (JCA-1), Schedule F-1, and A-16 (JCA-2), Schedule F-1.1, page 1, lines 24 through 26, column (c). Company witness Miller uses these results to break down power supply charges for full-service customers into capacity related and non-capacity related, according to the November 21, 2017 Order in Case No. U-18239.

VII. <u>SUBSTATION OWNERSHIP CREDIT CALCULATION</u>

Q. Please describe Exhibit A-19 (JCA-5).

A. Exhibit A-19 (JCA-5) shows the determination of the credit due to customers who own their own substations under the GPD Rate, following the methodology approved by the Commission in Case No. U-18322. The calculation determines the costs that have been allocated to GPD customers on Voltage 1 and Voltage 2 for substations and then determines the cost on a per kW basis for each voltage level. The calculation follows the same methodology for both voltages using figures from Exhibit A-16 (JCA-2), Schedule F-1.1, Test Year COSS – Version 2, and Exhibit A-16 (HWM-3), Schedule F-3, Present and Proposed Revenue Detail. Voltage 1 calculations are presented in column (b) and Voltage 2 in column (c). Lines 1 through 5 display the different items included in the substation rate base, with the total showing in line 6. The substation rate base is then multiplied by the pre-tax return on equity rate in line 7, which results in the pre-tax return in line 8. Expenses in lines 9 through 11 are added to the pre-tax return, while revenue credits in line 12 are subtracted from the pre-tax return to produce the total revenue requirement for substations in line 13. This total (in thousands of dollars) is divided by the maximum demand in MW in line 14 to determine the substation ownership credit in line 15. This is the credit on a dollar per kW basis that the Company is proposing be provided to Voltage 1 and Voltage 2 customers who do not benefit from Company-owned substations.

VIII. ALLOCATION OF SURCHARGES

Q. Please describe Exhibit A-20 (JCA-6).

A. Exhibit A-20 (JCA-6) shows the allocation, by rate class, of the following surcharges: (i) the Financial Compensation Mechanism ("FCM") amount provided by Company witness Troyer ($3.0 million); (ii) the DR refund supported by Company witness Steven Q. McLean ($2.1 million); and (iii) the Electric Rate Case Deferral sponsored by Company witness Myers ($12.6 million). The FCM amount is both energy and capacity related, as noted by Company witness Troyer; therefore, the Company allocated the cost to customers using the energy and capacity allocators developed in the Test Year COSS – Version 2. The DR Refund is capacity-related and the Electric Rate Case Deferral is distribution-related. However, considering that these amounts were originated prior to the test year, the allocations include the portion associated with the LTILRR. These results are then used to calculate the corresponding surcharges, discussed in the direct testimony of Company witness Miller.

Q. How is the Company proposing to allocate the Conservation Voltage Reduction ("CVR") Program Incentive to be collected through a surcharge described by Company witness Myers?

A. Company witness Myers described the CVR incentive surcharge based on the amount sponsored by Company witness Michael J. Delaney ($1.2 million). Considering that the associated investment benefits the Low Voltage Distribution circuits, per direct testimony of Company witness Blumenstock, the Company is recommending the use of allocator 230 – Class Peak at Primary - to assign the cost of the incentive. This allocator can be found in Exhibit A-16 (JCA-2), Schedule F-1.1, page 10, line 24.

IX. COMPLIANCE WITH SETTLEMENT AGREEMENT CASE NO. U-20134

Q. Is the Company complying with the Settlement Agreement approved by the Commission on January 9, 2019 for Case No. U-20134?

A. Yes. Per the Settlement Agreement in Case No. U-20134, the Company is addressing the following items:

> 16. Consumers Energy agrees that, in its next electric general rate case, the Company will provide a study analyzing the issue of the cost to serve customers who take standby service. The study will focus on customers with behind-the-meter generation capacity that exceeds 550 kw. The study will review both the actual demands that standby

> customers place on the system as well as the cost of the investments that are in place to provide standby service.
>
> 17. Consumers Energy agrees that, in its next electric general rate case, the Company will provide a cost of service study version that separates the RS and RT rate classes, for informational purposes. In addition, Consumers Energy agrees that, in its next electric general rate case, the Company will provide a cost of service study that reflects projected load reductions to each rate class resulting from rate changes and demand response programs.

Q. Is the Company providing a study analyzing the issue of the cost to serve customers who take standby service per item #16 from the settlement agreement in Case No. U-20134?

A. Yes. The Company engaged Brattle Group, a third-party economic consultant, to prepare the study, which is provided in Exhibit A-21 (JCA-7). The study concluded the following: (i) the Company under-collected production and transmission costs when comparing its embedded cost study to the total revenues calculated with the same determinants and the approved rates from Case No. U-20134, and (ii) "[c]ontract demand, rather than observed demand, may be a more appropriate allocator of demand-related distribution costs for Standby customers because Consumers must plan for Standby customers' contract demand" (Exhibit A-21 (JCA-7), page 8). As indicated earlier in my direct testimony, the Company has made a proposal to address this gap.

Q. Was the scope of the study done by Brattle Group limited to business customers taking stand by service over 550 kW?

A. No. For informational purposes, Brattle Group also evaluated the cost to serve residential customers with distributed generation. The study concluded that these residential customers with distributed generation are currently more expensive to serve than customers without distributed generation, as shown in the slide below.

Cost Allocation Analysis

Residential Customer Costs

The costs allocated to Residential NEM customers differ depending on whether they are included in the Residential class or are treated as a separate class.

Annual Cost Comparison for Non-NEM Residential Class and Residential NEM Customers

	Total Allocated Cost ($)		Unitized Allocated Costs		
Cost Type	**Non-NEM Residential**	**Residential NEM**	***Measure***	**Non-NEM Residential**	**Residential NEM**
Production					
Net Capacity Cost	$539,242,902	$252,051	*$/kW CP*	$150	$202
Capacity-Related Cost Offset	$279,809,565	$201,661	*$/kW CP*	$78	$162
Non-Capacity-Related Cost	$561,603,008	$472,444	*$/kWh Sales*	$0.043	$0.042
Total	**$1,380,655,475**	**$926,156**			
Distribution					
Demand-Related Cost	$633,234,152	$661,939	*$/kW NCP*	$165	$181
Customer-Related Cost	$140,735,282	$144,813	*$/Customer*	$88	$88
Total	**$773,969,434**	**$806,752**			

	Residential Class	Residential NEM
Customer Count *End of 2018*	1,604,505	1,654
CP	3,600,074 kW	1,247 kW
NCP	3,843,643 kW	3,661 kW
Sales	13,089,908,238 kWh	11,335,089 kWh

Sources and Notes:

- Brattle calculated allocated costs by applying allocators for Non-NEM Residential and Residential NEM classes to total production and distribution costs. The Consumers COS Model – 2018 Load Study was used as the basis of this analysis.
- Non-Capacity-Related Cost includes energy O&M, transmission, power purchase, and fuel costs.

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Q. Is the Company providing a COSS that (i) separates the RS and RT rate classes, for informational purposes, and (ii) reflects projected load reductions to each rate class resulting from rate changes and DR programs per item #17 from the settlement agreement in Case No. U-20134?

A. Yes. Exhibit A-22 (JCA-8) uses Test Year COSS – Version 2 as the starting point and incorporates (i) the separation of the RS and RT rate classes, and (ii) the reduction of the 4 CP of each corresponding customer class resulting from the projected reductions in load in the test year from residential DR programs (Central Air Conditioning Peak

Cycling Program and Dynamic Peak Pricing Program) and business DR programs, in addition to the impact from the residential Summer Time-of-Use rate change. The projected 4 CP load reductions from DR and rate changes in the test year, in addition to those included in the three-year historic load profile, are 413 MW for residential and 472 MW for business, per data provide by Company witness Breuring and Company witness McLean.

Q. Is the Company making a proposal for the Commission to consider any of these two updates?

A. No. The Company is only providing this COSS to comply with the terms of the settlement agreement in Case No. U-20134. First, in Case No. U-20134, the Commission approved the transition of all RT customers to the Residential Smart Hours rate, which is expected to be completed before the end of the year 2020. Therefore, it is no longer appropriate to utilize a load profile for Rate RT for the test year in this case. Second, the Company believes that the approved methodology of using the average of three-year historic load profiles continues to be reliable and appropriate to reflect how customers are using the system.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

RACHEL L. BARNES

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Rachel L. Barnes, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Rate Analyst II in the Rates and Regulation Department.

Q. Please state your educational background.

A. I graduated from Lake Superior State University in May 2001 with a Bachelor of Business Administration degree. In addition, I have attended a number of courses on utility rate making.

Q. Please describe your responsibilities as a Senior Rate Analyst II.

A. My primary responsibilities include tariff filings for Gas Cost Recovery and Power Supply Cost Recovery proceedings, developing tariff exhibits for general electric and natural gas rate cases, preparing rate and monthly bill comparisons, and implementing tariff changes, Company-wide, based on orders from the Michigan Public Service Commission ("MPSC" or the "Commission").

Q. Have you previously been a witness, or supported witnesses, in any proceedings before the MPSC?

A. Yes. I have sponsored the Company's proposed tariff changes and rate schedules in General Electric Rate Case Nos. U-14347, U-17990, and U-20134, as well as in General Natural Gas Rate Case No. U-15986. In addition, I sponsored testimony in Case No. U-16441, a reconciliation of the revenues collected during a self-implementation interim period. I also sponsored rebuttal testimony in Case Nos. U-17095-R and U-17334, supporting the roll-in methodology for the over-collection or under-collection of Power Supply Cost Recovery and Gas Cost Recovery revenues.

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

A. The purpose of my direct testimony is to present the Company's proposed language changes to its electric rate schedules.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-23 (RLB-1)		Summary of Tariff Changes; and
Exhibit A-16 (RLB-2)	Schedule F-5	Proposed Tariff Sheets (MPSC No. 14 Redlined Version).

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

A. Yes.

Q. Please describe Exhibit A-23 (RLB-1).

A. Exhibit A-23 (RLB-1) provides a summary and explanation of the tariff changes proposed in this case to the Company's Electric Rate Book.

Q. Please describe Exhibit A-16 (RLB-2), Schedule F-5.

A. Exhibit A-16 (RLB-2), Schedule F-5, Proposed Tariff Sheets (MPSC No. 14 Redlined Version) contains, in redlined format, per the Commission's filing requirements, all of the changes the Company proposes in this case to its current electric tariffs. These changes are discussed in my testimony or in the direct testimony of other Company witnesses. For example, the rationale for price changes to the Company's electric rate schedules are supported by the Company's rate design witness, Hubert W. Miller.

Q. Please explain the modifications to Rule C5.2 Bills and Payments.

A. Interval Data Estimation language was added to the tariff book on December 11, 2017 in Case No. U-18120. Since the addition of the language, the Company's standard residential rate has changed from Residential Service Secondary Rate RS ("Rate RS") to Residential Summer On-Peak Basic Rate RSP ("Rate RSP"). Rate RSP uses daily interval data for billing purposes, unlike Rate RS which uses monthly index data. This has dramatically increased the amount of data that is being handled by the Company's metering & billing systems. The increased number of customers requiring interval data for billing purposes is prompting changes to simplify the interval billing process when there are missing intervals. As a result, the modifications made to Rule C5.2 will help simplify the interval billing process, and will ensure the Company fully complies with the Administrative Rule[1] to bill customers on the lower tier rate, when there are missing intervals, while, at the same time, keeping the billing function efficient as it handles large amounts of metering data.

Q. Explain the proposal to Rule C6.2 Underground Policy of the Distribution Systems, Line Extensions and Service Connections Rule.

A. The Company is proposing additional language under Rule C6.2, Underground Policy, which sets forth the conditions under which the Company shall install underground electric distribution facilities when required to do so by state or local law or regulation. In the event that underground electric service is not required by the Company, but is instead required by state or local law or by regulation, the Company proposes that an adjustment may be made to the contribution in aid of construction to account for such a requirement. The Company proposes that such an adjustment is acceptable in these circumstances given

[1] Consumers Standards and Billing Practices for Electric and Natural Gas Service Rule 460.113(6).

that the undergrounding of electric distribution service is a requirement of a state agency and not the requirement of the MPSC or the Company's tariff.

Q. Please explain the changes made to Rule C-11, Net Metering Program.

A. Rule C-11 is being modified to include Self-Generation and the Distributed Generation Program, in addition to the Net Metering Program. The Company's current Self-Generation is for customers with generator installations less than 550 kW. The language is currently found within the tariff of each individual eligible rate. Self-Generation is proposed to be Rule C-11.1 and will be located on Tariff Sheet No. C-58.00. The Company's current Net Metering Program has been moved from Rule C-11 to Rule C-11.2 and begins on Tariff Sheet No. C-58.20. Program Capacity has been added as a defined term and a proposed final date of enrollment has been added to the Net Metering Program to indicate the transition of Net Metering to the Distributed Generation Program. Distributed Generation Program has been added as Rule C-11.3, and is located on Tariff Sheet Nos. C-64.10 through 64.80, to comply with the Commission's final order in Case No. U-18383 ("U-18383 Order"), issued on April 18, 2018. The Company's proposed Distributed Generation Program tariff is substantially similar to the tariff found on Attachment A of the U-18383 Order. Company witness Miller discusses the inflow/outflow methodology of the proposed Distributed Generation Program tariff.

Q. Please explain the proposed termination of Residential Service Secondary Rate RS, the Residential Service Dynamic Program, Residential Service Time-of-Day Secondary Rate RT, and the Experimental Residential Plug-In Electric Vehicle Charging Program.

A. As ordered in Case No. U-20134, pursuant to a settlement agreement, the Company has been modifying and testing the billing and accounting systems necessary to accommodate Peak Time Rewards and Critical Peak Price Demand Response provisions for residential customers on an opt-in basis, in addition to the Residential Smart Hours Rate and the Residential Nighttime Savers Rate. Upon completion, Residential Service Secondary Rate RS, the Residential Service Dynamic Program, Residential Service Time-of-Day Secondary Rate RT, and the Experimental Residential Plug-in Electric Vehicle Charging Program will no longer be offered as residential rate options.

Q. Please explain the addition of the Low Income Assistance Credit to Residential Rates.

A. The Low Income Assistance Credit ("LIAC") has been available for eligible gas customers since August 7, 2017, as authorized in Case No. U-18124. The Company is proposing to expand availability of LIAC to a limited number of eligible electric customers. The language included on Tariff Sheet Nos. D-15.00, D-37.00, D-41.00, and D-44.20 mirrors the proposed language in the Company's Gas Rate Case No. U-20650, filed on December 16, 2019. Additional information about the LIAC proposal can be found in the testimony of Company witnesses Steven Q. McLean and Hubert W. Miller.

Q. Please explain the proposed changes to the Residential Non-Transmitting Meter Rate RSM.

A. As ordered in Case No. U-20134, pursuant to a settlement agreement, the Residential Secondary Non-Transmitting Meter Rate RSM ("Rate RSM") was created for customers who elect a Non-Transmitting Meter. Customers electing a Non-Transmitting meter incur upfront and monthly charges, as stated in Rule C5.5 (found on tariff sheet C-25.00). Rate RSM uses monthly index data for billing purposes which requires a single meter read per billing period. In addition to customers who elect a Non-Transmitting Meter, the Company has a small population of customers with non-communicating meters. A non-communicating meter is unable to consistently transmit interval data to the Company for billing purposes; thus, the Company will lack sufficient information to provide a monthly invoice on the standard Residential Rate RSP, which requires interval metering data for billing. While a non-communicating meter lacks reliable interval data, an actual beginning and ending index read can be extracted from the meter, allowing impacted customers to receive an invoice using actual consumption data. The Company has determined the Non-Transmitting Rate as the most appropriate rate option for customers with a non-communicating meter because it does not require daily interval data for billing. Company Witnesses Brenda L. Houtz and Miller provide additional detail regarding customers with Non-Communicating meters.

Q. Why is the Company proposing changes to the Adjustment for Power Factor General Service Secondary Demand Service GSD?

A. Advanced Metering Infrastructure has made possible the metering of a power factor for customers on General Service Secondary Rate GSD ("Rate GSD"). The power factor adjustment on secondary rates is currently calculated by increasing capacity charges for that billing month in the ratio that 80% bears to the power factor. Modifications were made to the calculation of the Adjustment for Power Factor section for Primary Rates GPD, GPTU, EIP, and GSG-2 in Case No. U-17990 to make the calculation of the power factor adjustment clear. The proposed language changes for the Rate GSD Power Factor Adjustment will align the calculations of the power factor between secondary and primary customers and will simplify the calculation of the power factor adjustment.

Q. Please explain the proposed revisions to the Interruptible Service Provision – Market-Price Option "GI2" on Tariff Sheet Nos. D-66.00 through D-68.00.

A. Under the GI2 Provision, the customer designates an amount of Contracted Firm Capacity. Defined Interruptible Capacity is the amount that exceeds the Contacted Firm Capacity. The tariff change clarifies that, during an emergency event, the customer's load must not exceed the Contracted Firm Capacity or that usage is subject to penalties as specified in the tariff.

Q. Please explain the inclusion of former metal melting customers to be eligible to take service under the Company's Energy Intensive Rate EIP on Tariff Sheet D-74.00.

A. This clarification to the tariff will allow Metal Melting customers, who were forced to cease operations due to the current global market conditions, to qualify for Rate EIP in the event conditions improve and they can restart operations at their Michigan facilities.

Q. Please explain the proposed changes to the General Unmetered Experimental Lighting Rate GU-XL on Tariff Sheet Nos. D-93.00 through D-95.00.

A. The Company collaborated with the Michigan Municipal Association of Utility Issues on proposed changes to the Streetlighting Tariff Sheet Nos. D-93.00 through D-95.00.

Specifically, the Company is proposing to update those tariffs applicable to the Light Emitting Diode ("LED") streetlighting service. The Company is proposing to modify the title of the General Unmetered Experimental Lighting Rate GU-XL ("Rate GU-XL") to General Unmetered Light Emitting Diode Lighting Rate GU-LED ("Rate GU-LED"). Rate GU-XL has been effective for service rendered on and after April 27, 2010, as authorized in Case No. U-16203. Since that time, LED has become the accepted technology for Streetlighting. All references to "experimental" have been removed, and only LED unmetered lights are being served on Rate GU-LED. The contract period has been increased from two years to five years to align with the contract period on General Service Unmetered Lighting Rate GUL.

Q. Please explain the proposal to eliminate Rule E3.7 Load Profiling.

A. Rule E3.7, Load Profiling, only applies to Retail Open Access ("ROA") customers who do not have an Interval Data Meter or a Wireless Under Glass Meter. By the time a final order is issued in this case, all existing active ROA customers will have either an Interval Data Meter or a Wireless Under Glass Meter. Since the final order in the Company's previous Electric Rate Case No. U-20134, pursuant to a settlement agreement, the Company has replaced two-thirds of ROA meters that were dependent on a telephone line to transmit consumption and demand data with Wireless Under Glass meters, with the remainder scheduled for 2020, making Rule E3.7 irrelevant. The reference to load profiling was also removed from Tariff Sheet No. E-7.00.

Q. Are there any other tariff changes being proposed by the Company?

A. Yes. Information about the proposed tariff language for the Company's Peak Power Savers Program can be found in the testimony of Company witnesses McLean and Miller.

Information about the Long Term Industrial Load Retention Rate tariff can be found in the testimony of Company witness Michael P. Kelly. In addition, information about the proposed tariff language for the Company's GSTU and GSD Interruptible Service Provision can be found in the testimony of Company witnesses McLean and Miller. The remainder of the Company's proposed tariff changes are described in Exhibit A-23 (RLB-1), which provides a summary and explanation of all the tariff changes being proposed by the Company in this case.

Q. Does this complete your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697

DIRECT TESTIMONY

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

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

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

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

Q. What are your current responsibilities?

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

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

A. I received a Master of Business Administration Degree with a Finance concentration from the Katz Graduate School at the University of Pittsburgh in 2002. Upon receiving this degree in May 2002, I joined Ford Motor Company as a Financial Analyst. During my seven years of employment at Ford, I worked in various finance roles throughout the company, including Assembly Operations, Powertrain Operations, Ford Motor Credit, and the General Auditor's Office. My responsibilities within these organizations included, but were not limited to, forecasting of and variance reporting on, all Income Statement and Balance Sheet line items, as well as business process auditing. In July 2009, I left Ford Motor Company 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-16581, the Company's 2011 Application for biennial review of the RE Plan;
- Case No. U-16543, the Company's 2011 Application to Amend 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; and
- Case No. U-20650, the Company's 2019 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's electric business.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

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

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

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

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

III. <u>EXHIBITS FOR CERTAIN FILING REQUIREMENTS – CREDIT RATINGS AND RECENT UTILITY BOND ISSUANCES</u>

IV. <u>SUMMARY AND CONCLUSIONS</u>

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-14 (MRB-1)	Schedule D-1	Overall Rate of Return Summary;
Exhibit A-14 (MRB-2)	Schedule D-1a	Capital Structure Development;
Exhibit A-14 (MRB-3)	Schedule D-1b	Comparison of Development of Capital Structure for the Projected Year Ending December 31, 2021;
Exhibit A-14 (MRB-4)	Schedule D-2	Cost of Long-Term Debt;
Exhibit A-14 (MRB-5)	Schedule D-3	Cost of Short-Term Debt – Revolver/Commercial Paper;
Exhibit A-14 (MRB-6)	Schedule D-4	Cost of Preferred Stock;
Exhibit A-14 (MRB-7)	Schedule D-6	Short-Term Debt Utilization;
Exhibit A-24 (MRB-8)		Current and Historical Credit Ratings;

Exhibit A-25 (MRB-9)	Recent Utility Corporate Bond Issuances;
Exhibit A-26 (MRB-10)	Peer Company Equity Ratios
Exhibit A-27 (MRB-11)	Rating Agency Adjusted FFO Analysis; and
Exhibit A-28 (MRB-12)	Moody's Rating Action for DTE Energy Gas

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

A. Yes.

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

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

A. I am recommending that the capital structure shown on Exhibit A-14 (MRB-1), Schedule D-1, be used in this case. This represents the actual capital structure as of December 31, 2018, 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 December 31, 2021. 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 52.50%. The equity ratio as a percentage of total capital is 42.80%.

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

A. I am assuming an ROE for Consumers Energy's electric business of 10.50%. This ROE is recommended by Company witness Todd A. Wehner and explained in further detail in his direct testimony.

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

A. I am recommending an overall rate of return of 6.09% 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. The cost of the components and the weighted cost are shown in columns (e) through (i). The overall rate of return that I am recommending is the weighted cost of the various components of the capital structure.

II. CAPITAL STRUCTURE AND COST RATES

A. Development of Capital Structure

Q. What is capital structure?

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

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

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

Company's capital structure also includes the balance from the Company's renewable liability.

Q. What is common equity and preferred equity?

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

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

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

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

A. I started with the actual balances of long-term debt, preferred stock, common equity, short-term debt, deferred income taxes, and ITC as of December 31, 2018, as shown in Exhibit A-14 (MRB-2), Schedule D-1a, page 1, column (e). I then made the adjustments shown in column (f) to arrive at the average test year balance ending December 31, 2021, in column (g) that I am recommending be used in this case.

Q. Please explain the common equity adjustment of $2.175 billion.

A. I have projected that the 13-month common equity balance for the test year will be $2.175 billion higher than the December 31, 2018 balance. The common equity adjustment of $2.175 billion consists of two components. The first is an adjustment to reflect $344 million in projected retained earnings from January 2019 through December 2021. The second is an adjustment of $1.831 billion to reflect the projected equity infusions from January 2019 through December 2021.

Q. What are retained earnings?

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

Q. Please explain the retained earnings adjustment of $344 million.

A. Since I started with the December 31, 2018 balance for common equity, it was necessary to make an adjustment to reflect the increase in the common equity balance through retained earnings that will occur through December 31, 2021.

Q. Please explain how you calculated the change in Consumers Energy's retained earnings from January 2019 to November 2019.

A. For the period of January 2019 through November 2019, I relied on actual changes in retained earnings, as reported by the Company's Rate Department in its monthly cost of capital study.

Q. Please explain how you projected the change in Consumers Energy's retained earnings in December 2019.

A. Since retained earnings do not increase evenly throughout the year, I assumed that the change in retained earnings in December 2019 was equal to the actual change in retained earnings from December 2018.

Q. Please explain how you projected the change in Consumers Energy's retained earnings from January 2020 through the test period ending December 2021.

A. Consumers Energy has a long-standing policy of using an 80% dividend payout ratio. I assumed Consumers Energy's retained earnings rate to be $11.75 million per month, or $141 million per year from January 2020 through December 2021. Failure to reflect retained earnings would understate the common equity balance for the test year.

Q. Please explain how you arrived at Consumers Energy's retained earnings rate of $141 million per year.

A. Based on Consumers Energy's Securities and Exchange Commission ("SEC") Form 10-K for 2018, I determined that Consumers Energy's net income for the 12-month period ended December 31, 2018, was $703 million. I used this amount as a proxy for the future net income and assumed a dividend payout ratio of 80%. Using these assumptions, I calculated an annual retained earnings amount of $141 million [$703 * (1-0.80)]. Exhibit A-14 (MRB-2), Schedule D-1a, page 3, shows the projected monthly retained earnings balance and calculates the 13-month average for the period ending December 31, 2021.

Q. What are equity infusions?

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

Q. Why did you make a $1.831 billion adjustment for the new equity infusions in your recommended capital structure?

A. This is the amount needed to hold a 52.50% equity ratio for the test period in this case. CMS Energy made an equity infusion into Consumers Energy of $350 million in January 2019 and made an equity infusion of $325 million into Consumers Energy in June 2019. The timing and amounts of each of these 2019 infusions are consistent with the Company's filing in Case No. U-20322. In addition, CMS Energy plans to make an equity infusion into Consumers Energy of $350 million by February 2020, $300 million by June 2020, $400 million by February 2021, and $310 million by June 2021. Accordingly, I reflected this in the equity balance for the test year for this case. The impact of these equity infusions on the cumulative balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 3. The 13-month average for the period ending December 31, 2021 is $1.831 billion. When the 13-month average for the equity infusions of $1.831 billion is combined with the $344 million retained earnings adjustment, the increase to equity capital is the $2.175 billion shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 1.

Q. How did the Company arrive at this level of equity infusions for 2020 and 2021?

A. The Company reviews a number of factors in determining the level of required equity infusions, including the level of cash flows, capital expenditures, and the resulting credit metrics. The Company also considers the current mix of debt and equity (equity ratio) and how to strike the optimal balance for customers. Given these considerations, the Company is committed to lower its overall equity ratio, from 53.46% for the 13-months ended December 2018, by almost 100 basis points in the test year of this case.

Q. How did you determine that 52.50% was the optimal level for the Company and customers and why is it important to approve the proposed equity ratio?

A. My testimony describing the key factors and providing evidence that supports the proposed equity ratio of 52.50% is organized as follows:

i. <u>Peer Equity Ratios are Higher and are Trending Up</u>

ii. <u>Tax Cuts and Jobs Act of 2017 ("TCJA" or "Tax Reform") has Negatively Impacted Cash Flow and Credit Metrics</u>

iii. <u>Optimal Equity Ratio / ROE Balance</u>

iv. <u>Ability to Fund Significant Capital Expenditures at Optimal Rates</u>

v. <u>Rating Agency Adjustments Lower the Equity Ratio</u>

vi. <u>Debt on a Financial Basis Lowers the Equity Ratio</u>

vii. <u>Summary</u>

i. <u>Peer Equity Ratios are Higher and are Trending Up</u>

Q. Have you performed an assessment of how the 52.50% equity ratio proposed in this case compares to other utilities?

A. Yes. For each of the companies represented in Company witness Wehner's ROE proxy group, I calculated the equity ratio (as a percentage of permanent capital at the regulated subsidiary level) at year-end 2018. This is reflected on Exhibit A-26 (MRB-10). The average equity ratio for the Company's peer group was 53.2%, 70 basis points higher than the 52.50% proposed for Consumers Energy in this case. Despite this higher peer average, I am proposing a ratio of 52.50%, which balances capital investment plans, credit metrics, and customer rate impacts, and continues to support affordable utility infrastructure financing for the state of Michigan.

Q. What been the recent trend in authorized equity ratios?

A. Average authorized equity ratios have increased. To combat the negative cash flow impacts of recently passed Tax Reform legislation (which I will discuss later in my testimony), many utilities have requested higher equity ratios. The average authorized equity ratios adopted by utility commissions so far in 2019 have been higher than 2018 and 2017. As noted by MPSC Staff ("Staff") in Case No. U-20479 (SEMCO Energy Gas Company's recent general rate case), the average authorized equity ratio for 2017, 2018, and the first half of 2019 are 49.88%, 50.09%, and 54.60% respectively. Staff recommended an equity ratio of 55.15% in that case, somewhat higher than the 2019 national average authorized equity ratio.

Q. Why is it appropriate to consider peer company equity ratio averages and trends in determining the appropriate equity ratio for the Company in this case?

A. In Case No. U-20322, the Company's most recent gas rate case, Staff considered national averages of authorized ROEs in developing its ROE recommendation. In its Order in that case, the Commission cited Staff's average ROE analysis as one of the factors considered in determining the Company's approved ROE. While the Company argued that Staff's average ROE analysis was incomplete in that case, Staff and the Commission considered peer averages an important piece of evidence in the ratemaking process. To be consistent with that philosophy, it is appropriate to consider peer company equity ratio averages and trends in determining the equity ratio for the Company in this case.

ii. Tax Reform has Negatively Impacted Cash Flow and Credit Metrics

Q. Should recently enacted Tax Reform legislation be considered in determining the appropriate common equity balance and equity ratio for the Company in this case?

A. Yes. The TCJA, signed into law in December 2017, brought broad, widespread changes to the federal tax system and has had significant impacts on U.S. utilities. The TCJA, effective beginning in January 2018, reduced the corporate tax rate and affects current and deferred tax accounting methods used by utilities. While the savings from lower tax rates will be passed on directly to our customers, those same savings reduce future cash inflows to the Company. The reduced cash inflows weaken the Company's credit metrics which degrades the Company's credit quality, potentially increasing financing costs. It is important to note that, although Tax Reform became effective in January 2018, the unfavorable cash impact of the TCJA was not fully realized in 2018.

Q. When did the Company begin to experience the negative cash impacts of the TCJA?

A. On February 22, 2018, after the enactment of the TCJA, the Commission issued an order in Case No. U-18494 adopting a three-step approach to address the impacts of the federal income tax reduction arising from the TCJA. The first step, the Credit A proceeding, determined the rate credit based on the new tax rate going forward. The second step, the Credit B proceeding, determined the rate credit from January 1, 2018, to the date of the order in the utility's Credit A case. The third step, the Calculation C proceeding, captured the remaining impacts of the TCJA. The reduction in current tax expense collection (Credit A) did not begin until July 2018 for the gas utility and August 2018 for the electric utility. Additionally, the reduction in deferred tax expense collection (Calculation C) did not begin until October 2019.

Q. How do these impacts of the TCJA relate to the appropriate equity ratio that should be approved in this case?

A. A key financial metric used by rating agencies is the ratio of Funds From Operations ("FFO") to Debt ("FFO to Debt ratio"). The calculation of this financial metric includes, in part, both the equity ratio and the authorized ROE of the Company; thus, there needs to be a balance between the Company's equity ratio and ROE that will ensure that this key financial metric does not drop and cause significant credit deterioration. An equity ratio of 52.50% and an ROE of 10.50%, as recommended by the Company in this case, results in an FFO to Debt ratio that is sufficient in striking this balance.

Q. What is a FFO to Debt ratio?

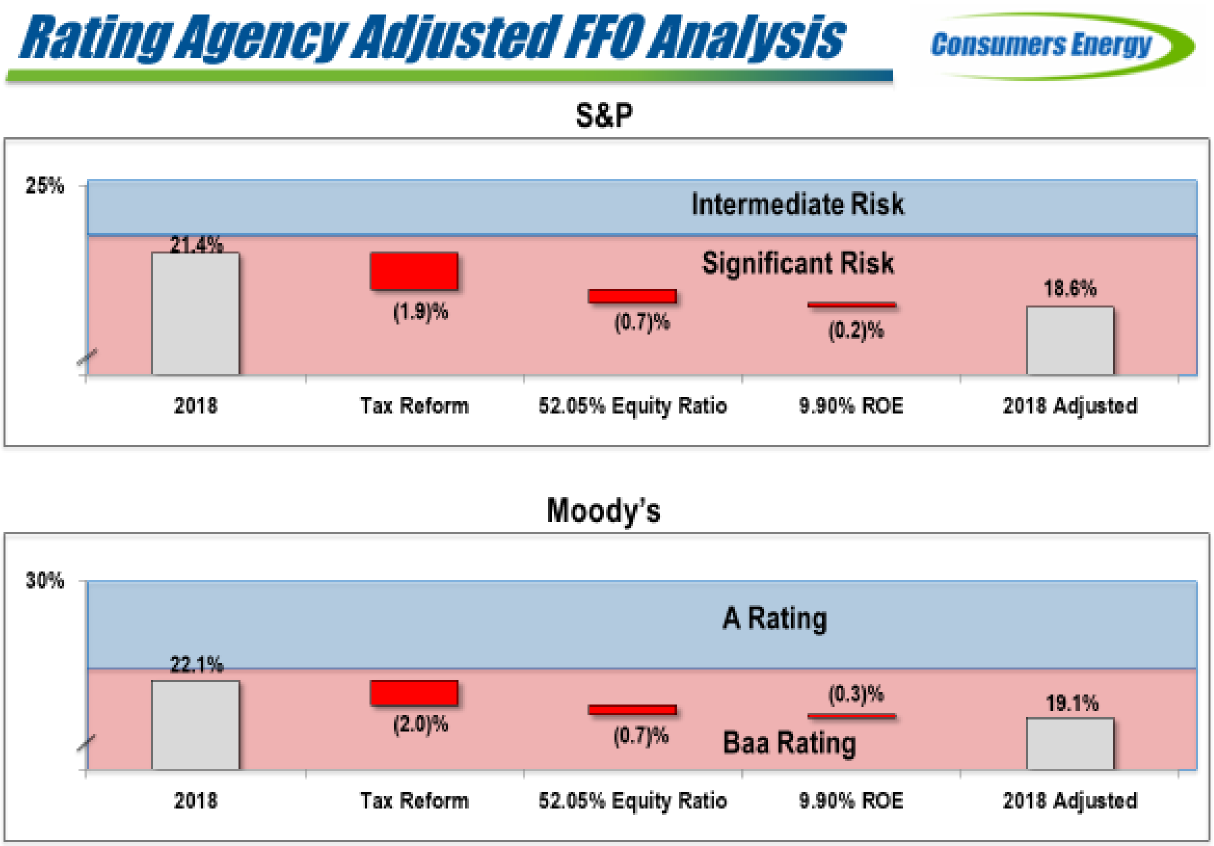
A. An FFO to Debt ratio is a financial metric that compares a company's cash flow from operating activities to a company's leverage, or debt outstanding. It can also be described as a payback ratio, reflecting the company's ability to repay its outstanding debt with operating cash flow. A higher FFO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

Q. What is the impact to the rating agencies' calculation of FFO to Debt ratios for the Company as a result of the enactment of the TCJA?

A. I have calculated the impact of the TCJA on the Company's FFO to Debt ratio on Exhibit A-27 (MRB-11). Starting with actual historical ratios for Standard and Poor's ("S&P") and Moody's Investors Service ("Moody's"), I layered in the impact of the TCJA as an adjustment to FFO and debt. This provides an indication of this key metric for the Company post-Tax Reform. As shown on Exhibit A-27 (MRB-11), column (b), FFO is reduced by $138 million (starting with 2018 actuals, which already include partial impacts of the TCJA) for both S&P and Moody's. Assuming approximately half of this reduction in cash is replaced with long-term debt, the S&P ratio is reduced by 190 basis points and the Moody's ratio is reduced by 200 basis points. The impact of this significant deterioration in credit metrics on the Company's credit quality is discussed in more detail in Company witness Wehner's direct testimony.

Q. What would the impact to the rating agencies' FFO to Debt ratios be assuming, in addition to the impacts of the TCJA, the Company realized an equity ratio of 52.05% and an ROE of 9.90%?

A. Lowering the equity ratio and the ROE would reduce the Company's overall cost of capital and rate of return. This, in turn, lowers the Company's cash flow and FFO to Debt ratio. The Company would also have to increase its long-term debt to achieve an equity ratio of 52.05%. This increase in debt would also weaken the Company's FFO to Debt ratio. As shown on Exhibit A-27 (MRB-11), moving to a 52.05% equity ratio and a 9.90% ROE would lower the FFO to Debt ratio by approximately an additional 90 basis points for S&P and approximately an additional 100 basis points for Moody's. This is on top of the significant reduction already caused by the enactment of the TCJA and would lead to a major deterioration in the credit quality of the Company as assessed by the rating agencies' key financial metric. The impacts of these adjustments are summarized in the following table:



Q. What are the risk category / credit rating thresholds for S&P and Moody's depicted in this table?

A. According to paragraph 123, Table 18, of S&P's published Corporate Methodology, which can be found on their website (www.standardandpoors.com), an adjusted FFO to Debt ratio of 23% is the threshold between an Intermediate Risk profile and a Significant Risk profile. According to page 22 of Moody's published Regulated Electric and Gas Utilities rating methodology which can be found on their website (www.moodys.com), an adjusted FFO to Debt ratio of 22% is the threshold between an "A" rating and a "Baa" rating when evaluating a Company's financial strength. As demonstrated in Exhibit A-27 (MRB-11), the impacts of Tax Reform, in combination with an equity ratio of 52.05% and a 9.90% ROE (as approved in Case No. U-20322), are reflective of FFO to Debt ratios of 18.6% for S&P and just above 19% for Moody's, which is well below the established thresholds. This places the Company's credit quality at risk.

Q. What are the risks if the Company's key financial metrics and credit quality weaken?

A. Rating agencies have stated that the Company's credit rating could be lowered if core financial measures underperform. This risk was realized by DTE Gas last year. In July 2019, Moody's downgraded DTE Gas from A2 to A3. This rating action is shown on Exhibit A-28 (MRB-12). In conjunction with this action, Moody's downgraded the ratings on DTE Gas' debt, including its senior secured First Mortgage Bonds, which were downgraded from Aa3 to A1. In its statement on the downgrade, Moody's stated that "the robust investment program of DTE Gas, combined with the negative cash flow effect of federal Tax Reform, continue to put pressure on its financial metrics, weakening its overall credit profile." See Exhibit A-28 (MRB-12). In light of Moody's actions, the maintenance of the Company's strong credit ratings will be critical in allowing the Company to finance significant capital investments while keeping the cost of capital lower. The Company is being proactive in recommending an equity ratio and ROE in this case that is supportive of the Company's current credit ratings.

Q. Are you aware of any recent changes in the Company's credit ratings?

A. Yes. In October 2019, S&P raised the issuer credit rating on Consumers Energy from BBB+ to A-.

Q. Why did S&P change the Company's credit rating?

A. In July 2019, S&P issued a revised credit rating methodology. The methodology was revised to take into account the impact of the credit profile of a company's parent on the subsidiary, and vice versa.

Q. Does S&P's change in the Company's credit rating indicate an improvement in the Company's underlying business?

A. No. This rating action was the direct result of the change in S&P's rating methodology and not a change or improvement in the Company's underlying business. Further, this rating action affects only Consumers Energy's issuer (overall) credit rating. There was no change to the ratings on the Company's senior secured debt or commercial paper, either of which would impact the Company's cost of debt financing.

iii. <u>Optimal Equity Ratio / ROE Balance</u>

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

A. As shown earlier in my testimony, ROE and equity ratio are two inputs in determining the Company's ratio of FFO to Debt, and FFO to Debt ratios are used by credit agencies to determine the Company's financial health. Consequently, it is important to recognize that the Company's ROE and equity ratio cannot be evaluated in isolation, but should, instead, be viewed as interconnected components that determine the Company's overall financial health. This relationship is illustrated in Company witness Wehner's Exhibit A-115

(TAW-3) which provides a mathematical development of how ROE and equity ratio determine a company's FFO to Debt ratio over the long term, assuming steady state conditions. An ROE of 10.50%, when taken together with an equity ratio of 52.50% results in an FFO to Debt ratio that is supportive of the Company's current credit ratings. A lower authorized ROE would, therefore, necessitate a higher approved equity ratio to maintain the same level of financial health. The relationship between the equity ratio, ROE, and rating agency credit metrics is discussed in more detail in Company witness Wehner's direct testimony.

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

A. Multiplying the equity ratio by the ROE produces a weighted cost or "rate of return." This is shown on Exhibit A-14 (MRB-1), Schedule D-1. On line 6 of this exhibit, the equity ratio of 52.50% from column (c) is multiplied by the ROE of 10.50% from column (e) to produce a weighted cost of 5.51%, shown in column (f). This is the weighted cost of common equity, a component of the Company's overall rate of return. This rate of return is important to consider since it takes into account the equity ratio in combination with the ROE. This rate of return should be set at an appropriate level that is supportive of the Company's current credit quality.

Q. What is the weighted cost of the equity ratio and ROE combination from the Order in Case No. U-20332, the Company's previous gas rate case?

A. Multiplying the equity ratio of 52.05% by the ROE of 9.90% from the order in Case No. U-20322 results in a weighted cost of 5.15%. It should be noted that DTE Energy, whose subsidiary DTE Gas was downgraded by Moody's in July 2019, has a weighted cost of 5.12% (equity ratio of 51.16% times ROE of 10.0%) which is comparable to the weighted cost from the Company's order in Case No. U-20322. Maintaining an authorized ROE of 9.90% without raising the approved equity ratio would result in cash flow and credit metric deterioration

iv. Ability to Fund Significant Capital Expenditures at Optimal Rates

Q. What are the Company's plans for capital investments and how does the equity ratio keep the cost of capital lower?

A. As set forth in the testimony and exhibits of Company witnesses Richard T. Blumenstock, Heather A. Breining, Karen M. Gaston, Scott A. Hugo, Kyle P. Jones, Steven Q. McLean, Latina D Saba, and Jeffrey D. Tolonen, the Company is making significant capital investments over the next five years to maintain and improve infrastructure to the benefit of customers ("Capital Expenditure Program"). During this time, the Company will rely heavily on the capital markets to fund these investments. Generally, a higher credit rating results in lower financing rates. Therefore, it will be especially important for the Company to maintain strong credit ratings over this period. The common equity balance, and equity ratio projected for the test year in this case, also enable the Company to maintain strong credit ratings and to better withstand any shocks in the financial markets. Strong credit ratings can help protect customers from spikes in interest rates, which increase the cost of capital, and/or inaccessibility to the capital markets, which serve as a key source of financing for the Company's Capital Expenditure Program. Strong credit ratings can also enable the Company to issue long-term debt ahead of upcoming maturities ("prefund") to take advantage of low interest rates without jeopardizing the Company's financial ratios. When market conditions are favorable, refinancing higher interest rate debt at lower rates reduces the Company's overall cost of capital included in customer rates. An example of this is the $850 million refinancing that the Company executed in November 2018. By refinancing at a lower interest rate, the Company eliminates interest rate risk, while realizing interest savings through the term of the called bonds. These savings and risk reductions are passed along to ratepayers in the form of a lower cost of capital.

Q. Do rating agencies consider the size of the Company's Capital Expenditure Program in evaluating its credit quality?

A. Yes. Consumers Energy's large Capital Expenditure Program is generally indicative of higher risk due to the fact that the Company will need to access capital markets with greater size and or frequency. This exposes the Company to increased financial market and interest rate risk. In its downgrade of DTE Gas in July 2019, Moody's pointed to "the robust investment program of DTE Gas," along with the negative cash flow impact of Tax Reform as a basis of that downgrade. In its June 2019 credit opinion for Consumers Energy, Moody's noted the Company's elevated capital investment program and further noted that the investment program "will require continued regulatory support in order to maintain the company's current financial profile." It is, thus, critical for the Company to maintain an equity ratio that is supportive of its strong credit profile, particularly during this period of significant capital investment. Failure to do this will put the Company at risk of experiencing the negative credit rating impacts faced by other utilities such as DTE Gas.

Q. With regard to the Company's projected capital expenditures, is it possible to trace equity dollars directly to those individual capital projects?

A. No. In addition to equity infusions, the Company also funds capital expenditures with long-term debt financing. Further, in determining the projected capital structure for the

Company, a combined capital structure approach is utilized for both electric and gas rate cases. The combined capital structure is fungible and supports the Company's entire rate base. This is a long-standing approach that has been accepted and approved by the Commission for many years. As a result, it is not possible to tie dollar-for-dollar the equity issuances to specific electric capital projects described in this case. This same standard applies to long-term debt financing, which also cannot be directly tied to capital projects. The capital expenditures in this case are identified, quantified, and supported by the Company's various capital witnesses.

v. Rating Agency Adjustments Lower the Equity Ratio

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

A. Certain credit rating agencies (e.g., Moody's) include securitization debt as additional debt when calculating equity ratios. Other credit rating agencies (e.g., S&P) also include Power Purchase Agreements ("PPAs"), benefit obligations, and leases as additional debt when calculating equity ratios. When credit rating agencies increase debt in this way to include securitization debt, PPAs, benefit obligations, and leases, the equity ratio (the ratio of equity to debt) used to evaluate the Company's credit-worthiness is lowered. A 52.50% equity ratio calculated by the Company, thus, gets adjusted to a lower ratio by the credit rating agencies, which, in turn, diminishes the Company's credit strength. Incorporating the projected equity infusions in 2020 and 2021 in the common equity balance enables the Company to maintain reasonable equity ratios after the upward adjustments to debt made by credit agencies for securitization debt, PPAs, benefit obligations, and leases. The Commission recognized that these circumstances support the need for a slightly higher equity ratio in Case No. U-17735. These rating agency adjustments do truly reflect the debt-like nature of long-term fixed payment obligations, such as PPAs, and cannot be ignored.

Q. What is the impact of rating agencies' adjustments to debt in calculating the Company's equity ratio?

A. Rating agencies' adjustments significantly reduce the Company's equity ratio. For example, in calculating financial metrics for 2018, S&P increased the Company's debt balance for the following items:

- $658 million to reflect the impact of PPAs;
- $137 million for pension obligations; and
- $338 million for Asset Retirement Obligations.

This equates to $1.1 billion of additional debt as evaluated by S&P in their credit assessment. Adding this level of debt to the Company's proposed capital structure in this case would reduce the equity ratio from 52.50% to 49.27%. The rating agencies' debt adjustments support the need for the Company to maintain a relatively higher equity ratio before adjustment to be on par with comparable utilities after adjustment. In addition to lowering the Company's equity ratio, rating agency adjustments to increase debt also reduce the Company's FFO to Debt ratio. As explained above, a lower FFO to Debt ratio negatively impacts the rating agencies' view of the Company's credit quality.

Q. Is the Company's capital structure balanced from a rating agency perspective?

A. No. In fact, as shown above, rating agency adjustments reduce the Company's equity ratio below 50%. Given these rating agency adjustments, a regulatory equity ratio of at least

52.50% is necessary to support the Commission's desire, as stated in Case No. U-20322, for Consumers Energy to maintain an evenly balanced capital structure.

vi. <u>Debt on a Financial Basis Lowers the Equity Ratio</u>

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

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

Q. **How does the Company's equity ratio on a regulatory (ratemaking) basis differ from the equity ratio on a financial basis?**

A. Since items such as securitization debt, revolver borrowings, and capital leases are included in the calculation of the Company's equity ratio on a financial basis, the Company's debt is higher, and the resulting equity ratio is lower compared to a regulatory basis. For example, at the end of 2018, securitization debt was $277 million. Including securitization debt decreases the Company's equity ratio by 110 basis points at the end of 2018. Also, while the Company excludes revolver/commercial paper borrowings from permanent capital in its regulatory capital structure, these borrowings are considered "debt" on a financial basis. Including the $312 million short-term borrowings would decrease the Company's equity ratio an additional 110 basis points.

Q. What is the Company's equity ratio on a financial basis?

A. Based on Consumers Energy's balance sheet as reported in the Company's 2018 Form 10-K, the equity ratio for the Company, on a financial basis, was 49.5% at year-end 2018. While certain rating agencies exclude securitization debt from their credit metrics, most analysts and investors evaluate the Company based on SEC (financial-basis) reported results.

Q. Is the Company's capital structure balanced from a financial-basis perspective?

A. Yes. As shown above, the Company's equity ratio on a financial basis was just over 50%. Financial basis adjustments, taken together with rating agency debt adjustments, make it necessary for the Company to maintain a regulatory equity ratio of at least 52.50%. This regulatory equity ratio level is critical to support a balanced capital structure (preferred by the Commission) after these adjustments.

vii. Summary

Q. In summary, why is having a 52.50% equity ratio, assuming a 10.50% ROE in this case, the right balance for customers and the Company?

A. In my testimony, I have shown that authorized equity ratios across the country are trending up and are, on average, at 53.2%. This is higher than the 52.50% recommended by the Company in this case. I have also shown that in the wake of Tax Reform, an ROE below 10.50% and an equity ratio below 52.50% would lead to an FFO to Debt ratio that would not be supportive of maintaining the Company's current credit ratings. In addition, the Company is in the midst of a major infrastructure upgrade cycle throughout our service territory in Michigan. This will require billions of dollars in new capital funding to complete these needed upgrades for our customers. A healthy equity ratio and credit quality will be key in raising the necessary capital at the lowest overall cost to customers over the long term. Lastly, I have shown that rating agency adjustments, together with looking at debt on a financial basis, effectively lowers the equity ratio in the eyes of investors, analysts, and rating agencies. On a financial basis, the Company's capital structure is roughly evenly balanced. On a rating agency adjusted basis, the Company's capital structure is reflective of an equity ratio below 50%. It is, therefore, necessary for the Company to maintain a regulatory equity ratio of 52.50% to support the Commission's desire, as stated in previous rate cases, for Consumers Energy to maintain an evenly balanced capital structure

While lowering the Company's equity ratio from 53.46% in 2018, to the 52.50% recommended in this case may appear to have a near-term cost savings impact, as debt financing is presently less expensive than equity, such a move would result in a deterioration of credit quality and may lead to our customers paying higher financing costs over the long-term. The equity ratio of 52.50% is appropriate and reasonable under the current circumstances in the wake of federal Tax Reform, made in conjunction with the 10.50% ROE proposed by Company witness Wehner. While a higher equity ratio could be supported, the Company has heard and understands the input of the Commission and intervenors in previous rate cases and is attempting to strike the right balance for customers, the state of Michigan, and credit agencies by holding the equity ratio at the Company's filed position of 52.50%.

Q. Please explain the long-term debt adjustment of $1.867 billion.

A. I have projected that the average debt balance for the test year ending December 31, 2021 will be $1.867 billion higher than the December 31, 2018 balance. This adjustment consists of the following components:

Long-Term Debt (in millions) Month	Issuance	Retirement	Dec 31, 2021 Test Year Impact
May 2019	$300	$0	$300
May 2019	$0	($300)	($300)
Sep. 2019	$626	$0	$626
Oct. 2019	$75	$0	$75
May 2020	$300	$0	$300
Aug. 2020	$750	$0	$750
Oct. 2020	$0	($100)	($100)
Aug. 2021	$625	$0	$240
Subtotal			$1,891
Changes in Unamortized Fees			(25)
Total			**$1,867**

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

Q. Please describe the planned debt issuances in May 2020, August 2020, and August 2021.

A. The debt planned to be issued in May 2020 and August 2020 will be used for general corporate purposes of the Company including financing capital expenditures. The debt will also be used for the October 2020 retirement of $100 million. The debt planned to be issued in August 2021 will be used for general corporate purposes of the Company including financing capital expenditures. These planned debt issuances have been determined based on the Company's financing plans after evaluating cash and liquidity requirements for the Company.

Q. What long-term debt was included in developing the 13-month average amount outstanding for the period ending December 31, 2021?

A. Exhibit A-14 (MRB-4), Schedule D-2, shows the long-term debt that was included in developing the 13-month average for the period ending December 31, 2021. The average amount outstanding on line 54, column (j), ties to the 13-month average balance shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.

Q. Does this capital structure reflect the January 2020 pension contribution of $531 million as detailed in Company witness Christopher's direct testimony?

A. Yes. This pension contribution increases the Company's working capital and is part of rate base.

Q. What is your projection regarding the level of short-term debt balance for the test year ending December 31, 2021?

A. I have projected an average short-term debt balance for the test year of $139 million. This balance is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 10, column (b), and on Exhibit A-14 (MRB-2), Schedule D-1a, page 1, line 10, column (g).

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

A. The average short-term debt balance is composed of two components. The first is the average short-term debt – revolver/commercial paper balance of $137 million. The second is the average short-term debt – renewable liability balance of $2 million. These balances are shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, lines 1 and 3.

Q. What is revolver/commercial paper?

A. Revolver and commercial paper are two short-term financing options available to the Company. Revolver represents a revolving line of credit that allows the Company to borrow and repay as long as the outstanding balance remains within the credit limit, or capacity. Commercial paper represents debt issuances under the Company's Commercial Paper Program that are short-term in nature, typically 1 to 90-day maturities.

Q. How was the revolver/commercial paper short-term debt balance of $137 million developed?

A. Exhibit A-14 (MRB-7), Schedule D-6, shows the projected balances of short-term debt - revolver/commercial paper for the test year ending December 31, 2021, by month. I have arrived at these projections after considering the projected total monthly cash flow requirements, planned long-term debt (net) and equity issuances, and the amount of short-term financing available.

Q. How do these projections compare with the historical trend?

A. The profile of monthly balances is consistent with the historical trend where the Company borrows on short-term facilities during fall and winter months and no short-term funding is required during summer months. The resulting 13-month average is $137 million.

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

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

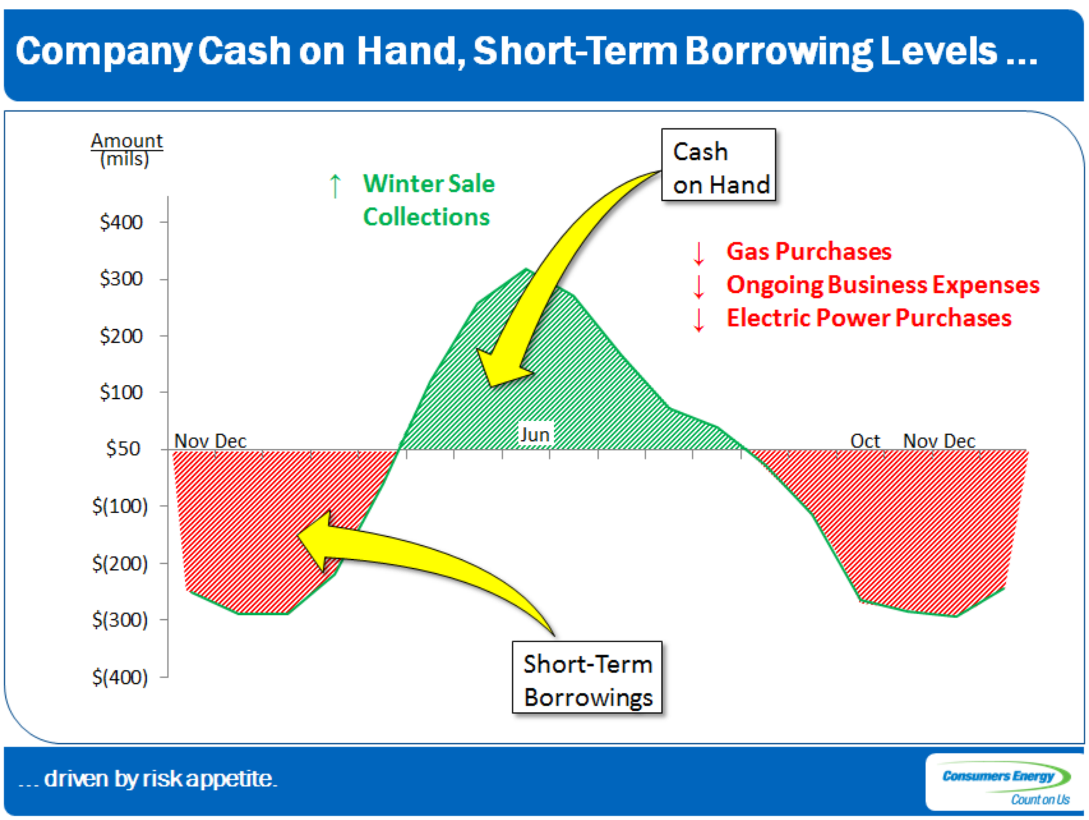
1.	Commercial Paper	$500 million*
2.	Scotiabank Revolver	$250 million
3.	JPMorgan Revolver	$350 million

*Takes away $500 million of the JPMorgan revolver's $850 million capacity (leaving $350 million available).

All of the projected balances for short-term debt – revolver/commercial paper are assumed to be issued under the Company's Commercial Paper Program. This is the least expensive short-term financing option to the Company and is assumed to be used first when the need arises, up to the $500 million capacity. The Company's $250 million Scotiabank revolving credit facility is the next least-costly, short-term financing option, with the remaining $350 million revolver ($850 million total capacity less $500 million drawn commercial paper) assumed to be used last.

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

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



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

A. No. Short-term financing markets can be volatile and, at times, access to those markets completely disappears as we witnessed less than a decade ago during the credit crisis. Based on the experience and judgment of the Company's Treasury Department, as well as members of the Financial Planning and Analysis Department, the Company does not pursue a strategy that maintains a permanent balance of short-term debt. However, the Company does fund seasonal fluctuations in its working capital with short-term debt as previously illustrated. Based on historical trends of these seasonal fluctuations, the difference between the maximum working capital surplus and the maximum level of working capital deficiency (peak-to-valley) is approximately $300 million to $600 million. The Company is comfortable financing between $200 million and $400 million of this gap with short-term borrowings. This leaves adequate undrawn capacity in the event of financial market volatility or disruption. In addition, rating agencies assess the Company's liquidity as a component of their overall credit rating methodology. Reducing cash balances and relying consistently on short-term borrowings would weaken the Company's liquidity metrics. Finally, if the Company were to establish and maintain a permanent level of short-term debt, this would be taken into account in calculating the appropriate equity ratio in this case. If the short-term debt balance were included in the debt-to-equity ratio calculation, the equity balance would need to increase in order to achieve the appropriate 52.50% equity ratio. This would result in a higher overall cost of capital. It should be noted that the Commission agreed with the Company's cash and short-term debt balances in Case No. U-20322.

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

A. The Company's $1.1 billion total short-term credit capacity is reasonable and necessary to conduct daily operations and also to keep credit risk at a reasonable level. To maintain strong financial health, it is important for the Company to maintain adequate short-term financing capacity for normal business operations and, in addition, extra or "backup" liquidity for cases of extreme market fluctuations or other unforeseen circumstances. As shown in Exhibit A-14 (MRB-7), Schedule D-6, the Company projects $350 million of short-term borrowings in November 2020 and November 2021. The most cost-effective method of financing this level of short-term debt is commercial paper. However, access to the commercial paper market requires an equivalent amount of revolving credit capacity as a "backstop." The current maximum capacity under the Company's Commercial Paper Program is $500 million; therefore, of the Company's $1.1 billion of revolving credit facilities, $500 million is used to support commercial paper issuance. The remaining $600 million of revolver capacity is a vital back-stop for capital expenditures and upcoming long-term debt maturities.

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

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

Q. How was the renewable surcharge liability balance developed?

A. I reflected the average balance of renewable surcharge liability. I have projected an average renewable surcharge liability of $2 million for this case. Exhibit A-14 (MRB-7), Schedule D-6, shows the monthly projections of this liability. The projections are consistent with Consumers Energy's RE Plan in Case No. U-18231.

Q. Please explain the deferred income tax adjustment of $326 million.

A. The Company's Tax Department has projected that the average deferred income tax balance for the test year ending December 31, 2021 will be $326 million higher than the December 31, 2018 balance. This increase is based on projecting book versus tax differences that the Company expects to record from January 2019 through December 2021. These adjustments total $326 million on a 13-month average basis for the test year. The development of the 13-month average deferred income tax balance is shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 4.

Q. How was the ITC balance determined?

A. The Company's Tax Department has projected that the average ITC balance for the test year ending December 31, 2021 will be $125 million, $25 million higher than the December 2018 balance. The balance is based on forecasted balances of both existing and anticipated new ITC credits that the Company expects to record from January 2019 through December 2021. These adjustments total $25 million on a 13-month average basis for the test year.

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

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

B. Development of Cost Rates

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

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

i. Long-Term Debt Cost Rate

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

A. I developed a 3.95% annual cost for long-term debt. The development of this annual cost rate is shown on Exhibit A-14 (MRB-4), Schedule D-2. Consistent with past Commission practice, the costs are determined on a net proceeds basis. I began with the debt issuances outstanding as of December 31, 2018. I then added the new debt issuances in May 2019, September 2019, and October 2019. These new debt issuances are shown on Exhibit A-14 (MRB-4), Schedule D-2, lines 30 through 31 and line 40. I then added the planned new debt issuances in May 2020, August 2020, and August 2021. These new debt issuances are shown on Exhibit A-14 (MRB-4), Schedule D-2, lines 33 through 35.

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 expense. 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 debt issuances in May 2019, September 2019, and October 2019.

A. Since the debt issuances in May 2019, September 2019, and October 2019 have already taken place, I used the actual interest rates specified in those bond issuances.

Q. The long-term debt issuances in September 2019 and October 2019 have relatively low interest rates. Is it expected that subsequent long-term debt issuances will have these same low interest rates?

A. No. The Company was able to achieve atypically low interest rates for these two issuances in 2019. While the Company continuously seeks financing alternatives that maximize interest savings, these two most recent 2019 issuances are not repeatable in the near term. The September 2019 issuance of $76 million provided a unique security for a very limited investor pool. The debt will bear interest at a rate of 3-month London Interbank Offered Rate ("LIBOR") minus 30 basis points, maturing 2069. The October 2019 issuance of $75 million was for a Pollution Control Revenue Bond ("PCRB"). The security will mature in 2049 and is locked in at a fixed rate of 1.80% for the initial 5-year term. While the savings from these low interest rates will be passed along to customers in the form of a lower cost of capital, they represent the maximum size limit available to the Company at the time of issuance. Further, while the Company will continue to try to identify similar opportunities, there are not any currently identified, and similar offerings are not and should not be expected or anticipated a regular basis going forward.

Q. Please explain the cost rate you assumed for the planned debt issuances in May 2020, August 2020, and August 2021.

A. I assumed that both 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 average of the projected 30-year U.S. Treasury rates of IHS Markit ("IHS") and Blue Chip Economic Indicators ("Blue Chip").

Q. What are IHS and Blue Chip and why are they reliable?

A. IHS and Blue Chip are companies that compile consensus economic forecasts and publish the results in a periodic report. These reports are widely used by companies in financial planning and analysis.

Q. What did you do next?

A. For each of these three planned debt issuances, I then added a 136 basis point spread. For the May 2020 and August 2020 planned debt issuances, the average of the IHS and Blue Chip 30-year U.S. Treasury rate forecasts for 2020 was 2.42%. Adding the 136 basis point spread resulted in a total coupon interest rate of 3.78% for these issuances. For the August 2021 planned debt issuance, the average of the IHS and Blue Chip 30-year U.S. Treasury rate forecasts for 2021 was 2.92%. Adding the 136 basis point spread resulted in a total coupon interest rate of 4.28% for this issuance. These interest rate calculations are shown on Exhibit A-14 (MRB-4), Schedule D-2.

Q. What is a spread?

A. A spread (also called a credit spread) reflects the extra compensation investors receive for bearing credit risk. Therefore, the total interest rate on a corporate bond is a function of both the Treasury rate and the credit spread.

Q. How was your assumed spread of 136 basis points over the U.S. Treasury rate calculated?

A. Unlike U.S. Treasury rates, spreads on long-term bond issuances are not projected by financial forecasting companies such as IHS or Blue Chip. This is because spreads are very difficult to predict. Interest rate spreads are based on a number of factors, most notably the Company's credit rating and the market conditions at the time of the debt issuance, including both same-day and short-term supply/demand dynamics. Given the lack of a reliable source for projected credit spreads, I used the average from the last 11 years. From 2008 to current, the average spread on a 30-year debt issuance for investment grade utilities was approximately 136 basis points.

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

A. Yes. There are two debt issuances shown on Exhibit A-14 (MRB-4), Schedule D-2, that have a variable interest rates. The Floating Rate First Mortgage Bond ("FMB") issuance shown on line 32, and the PCRB issuance shown on line 39 have variable interest rates.

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

A. The interest rate for the Floating Rate FMB is equal to LIBOR less 30 basis points. Therefore, I took the average of the projected three-month LIBOR rates from IHS and Blue Chip Forecasts (equal to 2.10%) and subtracted 30 basis points for an interest rate of 1.80%. For the PCRB, the interest rate has historically been approximately 70% of the three-month

LIBOR rate. Accordingly, I used 70% of the projected three-month LIBOR rate for the test year ending December 31, 2021 to estimate the cost of the PCRB. The estimated interest rate on the PCRB is 1.47% (2.10% * 70%).

Q. Please explain Exhibit A-14 (MRB-4), Schedule D-2, line 46.

A. Exhibit A-14 (MRB-4), Schedule D-2, line 46, represents the amortization of losses on reacquired Consumers Energy debt (including call premium) for refinancings. This amortization needs to be added to the interest cost on the refinanced debt to determine Consumers Energy's true financing cost for the long-term debt. The Commission recognized recoverability of these costs in establishing the cost rate in Case No. U-16794.

Q. How did you calculate the amount shown on Exhibit A-14 (MRB-4), Schedule D-2, line 46?

A. The amount of $5,107,000 shown on line 46 is based on the projected amortization expense during the 12-month period ending December 31, 2021.

Q. Please explain line 48 – PCRB Fees shown on Exhibit A-14 (MRB-4), Schedule D-2.

A. These PCRB Fees are related to the April 2005 PCRB issuance shown on line 39 of Exhibit A-14 (MRB-4), Schedule D-2. Consumers Energy incurs certain ongoing fees to maintain this debt security which is included in long-term debt for ratemaking purposes. These fees include ongoing bond remarketing expense and the trustee expense. I have included $46,000 for these expenses based on actual experience. These fees are prudent, reasonable, and customary for these types of tax-exempt securities and were approved for recovery in Case No. U-16794.

Q. Was this cost included in the development of the cost based on net proceeds for the PCRB issuance shown on Exhibit A-14 (MRB-4), Schedule D-2, line 39?

A. No. This cost was not incurred at the inception of this security, but rather incurred on an ongoing basis over the life of the security. Consequently, the cost is not included in the net proceeds calculation and are shown separately.

Q. Does the amount shown on Exhibit A-14 (MRB-4), Schedule D-2, line 48 – PCRB Fees include any PCRB Letter of Credit Fees?

A. No. Since the refinancing of these securities in 2008, the Company is required to provide Letters of Credit pursuant to bond arrangements and incurs costs to do the same. I have included the PCRB Letter of Credit Fees in the calculation of short-term debt cost, rather than as part of long-term debt cost, in this case.

ii. <u>Short-Term Debt Cost Rate</u>

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

A. I used a short-term debt cost rate of 3.46%. This cost rate is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, line 5.

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

A. As explained earlier, the short-term debt balance is composed of two components. The first is short-term debt – revolver/commercial paper. I calculated the annual cost of short-term debt – revolver/commercial paper to be $4.8 million. The second component is short-term debt – renewable liability. Since the balance of this component is so low, there is no cost assigned to it (under $100,000). This is shown on lines 1 and 3 of Exhibit A-14 (MRB-5), Schedule D-3, page 1, column (b). The total average balance of short-term debt, shown on Exhibit A-14 (MRB-5), Schedule D-3, page 1, line 5, column (a), is

$138.8 million. Dividing the total cost of $4.8 million by the total average short-term debt balance results in a total short-term debt cost rate of 3.46%, as shown in column (c).

Q. Please explain the cost of short-term debt – revolver/commercial paper.

A. As indicated above, I projected a cost of short-term debt – revolver/commercial paper of $4.8 million. The development of this cost is shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2. The cost of short-term debt – revolver has four components:

1. **<u>Interest on Borrowings</u>** – Equal to the projected outstanding balance times the projected interest rate. The projected balance, all assumed to be commercial paper, is $137.3 million, calculated on Exhibit A-14 (MRB-7), Schedule D-6. Commercial paper issuances are short term in nature, typically 1 to 90-day maturities. Interest charged on these short-term borrowings are based on several different factors, including market conditions, investor demand, and the tenor (number of days borrowed) of the issuance. I approximated the interest on commercial paper borrowings using the projected LIBOR[1] rate for the test year of 2.10%. This was multiplied by the projected balance of $137.3 million. Exhibit A-14 (MRB-5), Schedule D-3, page 2, shows the projected cost of $2.9 million for borrowings under the Commercial Paper Program;

2. **<u>Letter of Credit Fees</u>** – 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 $0.6 million for Letter of Credit Fees. The Letter of Credit Fees shown on Exhibit A-14 (MRB-5), Schedule D-3, page 2, pertains to the following:

   - Item 1 (line 28) - Normal business Letters of Credit to cover ongoing items such as fuel purchases or margin support;
   - Item 3 (line 30) – Letter of Credit to cover Midcontinent Independent System Operator, Inc. margin obligations;
   - Item 4 (line 31) – Letter of Credit related to the Palisades Power Purchase Agreement; and
   - Item 5 (line 32) – Letter of Credit related to PCRB tax exempt bonds;

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

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 $0.8 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 $0.5 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 and commercial paper agreements and are necessary to secure the availability of the financing and to keep the facilities available for the financing needs of the Company. The Company cannot avoid incurring these costs except by giving up the short-term borrowing facilities which would not be a sound business decision. If these fees are not recovered through short-term debt cost, then they need to be recovered as part of long-term debt cost. The cost of short-term debt – revolver/Commercial Paper Program represents the cost to provide $1.1 billion of needed liquidity to Consumers Energy.

Q. Why did you include Letter of Credit Fees for the Tax Exempt Bond in the calculation of Letter of Credit Fees?

A. The Letter of Credit facility for the Tax Exempt Bond is for the PCRB Letter of Credit that the Company is required to provide pursuant to bond arrangements. These Letter of Credit

Fees are prudent, reasonable, and customary. If these Letter of Credit Fees are not included as part of the short-term debt cost, then the fees should be included either as part of the long-term debt cost calculation or as separate expense items.

Q. What cost have you used for the short-term debt – renewable liability?

A. Section 21(4) of Public Act 295 of 2008 discusses the cost rate for the renewable liability, and it provides for "the creation of a regulatory liability that accrues interest at the average short-term borrowing rate available to the electric provider during the appropriate period." I have used the projected short-term borrowing rate available to the Company under its Commercial Paper Program of 2.10%. I then applied this rate to the projected average renewable liability balance for the test period of $1.5 million, shown on Exhibit A-14 (MRB-7), Schedule D-6. As explained above, since the balance of the renewable liability is so low, there is no cost assigned to it (under $100,000).

iii. Preferred Stock Cost Rate

Q. What is the annual cost of preferred stock?

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

iv. Common Equity Cost Rate

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

A. Company witness Wehner recommended an ROE range of 10% to 11%. Based on my recommended equity ratio of 52.50%, I used a cost rate of 10.50% for common equity. As explained earlier in my testimony, to the extent that the Commission authorizes a lower equity ratio than that proposed by the Company, a higher ROE is necessary to prevent the potential for adverse credit impacts. The Company generally believes it is preferable for the ratemaking equity ratio to reflect the Company's actual capital structure (i.e., ratemaking should match reality). The Company's capital structure and ROE recommendations in this case reflect the appropriate levels that the Commission should adopt with that principle in mind in order to preserve Consumers Energy's current favorable credit rating.

v. Other Cost Rates

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

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

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

Q. Please describe Exhibit A-24 (MRB-8).

A. Exhibit A-24 (MRB-8) is included per the rate case filing requirements. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides current and historical credit ratings with associated outlooks for the previous five years for the utility and its parent company. Exhibit A-24 (MRB-8) shows Consumers Energy's and CMS Energy's current and historical credit ratings, along with associated credit outlooks, for the previous five years as published by S&P, Moody's, and Fitch Ratings. The credit ratings include senior secured debt, commercial paper, senior unsecured debt, preferred stock, junior subordinated debt, hybrid preferred securities ratings, and preferred stock ratings.

Q. Please describe Exhibit A-25 (MRB-9).

A. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides certain information related to bond issuances. Exhibit A-25 (MRB-9) shows recent public utility corporate bond issuances for a period of three months prior to, and three months subsequent to, each of Consumers Energy's long-term public debt offerings issued during the 24 months prior to the date of the Application in this rate case. This summary includes the issue date, issuing company, type of offering (either secured or unsecured), amount of offering, coupon rate, S&P and Moody's credit ratings, maturity date, and spread on U.S. Treasury.

IV. 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, 2018, adjusted for the known and expected changes in long-term debt, common equity, short-term debt, deferred income taxes, and ITC, as shown on Exhibit A-14 (MRB-1), Schedule D-1. The cost rates developed are fair and reasonable and commensurate with the risks for the period of time rates are expected to be in effect. The cash flow and credit impacts of federal Tax Reform must be considered in evaluating capital structure and ROE in this case to proactively avoid credit deterioration. In addition, I have shown that when viewed from a financial or rating agency standpoint, the projected capital structure is balanced or under 50%. The Company has taken great care to do what is best for Michigan and balance both the short-term and long-term considerations in an attempt to optimize its capital structure and overall cost of capital for its customers. As shown on Exhibit A-14 (MRB-1), Schedule D-1, I recommend an overall after-tax rate of return of 6.09%.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

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

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

A. I am currently the Executive Director of Electric Planning. I began employment at the Company in May of 1994 in the electric transmission planning area where I performed planning studies on the Company's distribution and transmission systems. In April of 2002, I was assigned to the electric operations area where I oversaw engineering operations for the distribution and transmission systems. In August of 2009, I was assigned to the fuel supply area where I oversaw the Company's purchasing and transport functions for fuel for electric generation. In June of 2011, I assumed additional responsibilities including oversight of the Company's interaction in the Midcontinent Independent System Operator, Inc. ("MISO") markets; wholesale settlements and transactions functions; Power Supply Cost Recovery ("PSCR") activities; and planning for electric supply necessary to satisfy customers' energy and capacity needs. In September of 2019, I assumed my current position as Executive Director of Electric Planning.

Q. What are your responsibilities as Executive Director of Electric Planning?

A. My responsibilities as Executive Director of Electric Planning include oversight of all activities associated with planning for the Company's low voltage electric distribution networks, high voltage electric distribution networks, electric generation, energy and capacity supply, and system protection.

Q. What is your formal educational experience?

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

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 cases:

- Case No. U-16045-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2010;
- Case No. U-16432-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2011;
- Case No. U-16890: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2012;
- Case No. U-16890-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2012;
- Case No. U-17429: Approval of a Certificate of Necessity for the Thetford Generating Plant pursuant to MCL 460.6s and for related accounting and ratemaking authorizations;
- Case No. U-17317: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2014;
- Case No. U-17317-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2014;
- Case No. U-17752: Authority to amend its renewable energy plan approved in Case Nos. U-15805, U-16543, U-16581, and U-17301;
- Case No. U-17678: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2015;
- 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; and

- 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.

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

A. The purpose of my direct testimony is to (i) provide an overview of the Company's electric distribution system; (ii) provide an overview of the Company's electric distribution strategy; (iii) explain the historical performance of the Company's electric distribution system; (iv) explain the Company's Grid Modernization strategy; (v) explain the Company's projected capital investments in the electric distribution system; (vi) explain various technology projects that support electric distribution; (vii) explain the Company's projected electric distribution O&M spending; and (viii) introduce the Company's line loss study.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (RTB-1)	Schedule B-5.1	Electric Distribution Summary of Actual and Projected Capital Expenditures;
Exhibit A-29 (RTB-2)		Electric Distribution Summary of 5-year Historical Electric Capital Expenditures;
Exhibit A-30 (RTB-3)		New Business Program Summary of Actual and Projected Electric Capital Expenditures;
Exhibit A-31 (RTB-4)		Reliability Program Summary of Actual and Projected Electric Capital Expenditures;
Exhibit A-32 (RTB-5)		Capacity Program Summary of Actual and Projected Electrical Capital Expenditures;

Exhibit A-33 (RTB-6)	Demand Failures Program Summary of Actual and Projected Electric Capital Expenditures;
Exhibit A-34 (RTB-7)	Asset Relocation Summary of Actual and Projected Electrical Capital Expenditures;
Exhibit A-35 (RTB-8)	Electric Other Program Summary of Actual and Projected Electrical Capital Expenditures;
Exhibit A-36 (RTB-9)	Summary of Actual & Projected Electric & Common O&M Expenses;
Exhibit A-37 (RTB-10)	Summary of Actual & Projected Electric & Common O&M Expenses;
Exhibit A-38 (RTB-11)	Summary of Actual & Projected Electric & Common O&M Expenses;
Exhibit A-39 (RTB-12)	Summary of Actual & Projected Electric & Common O&M Expenses;
Exhibit A-40 (RTB-13)	Summary of Actual Capital Expenditures per Case No. U-20134 Settlement;
Exhibit A-41 (RTB-14)	Summary of Selected Distribution Project Concept Approvals;
Exhibit A-42 (RTB-15)	Distribution Projects Summary Projected Electric Capital Expenditures;
Exhibit A-43 (RTB-16)	Consumers Energy Electric Asset Management High Voltage Distribution Pole Inspection Specifications;
Exhibit A-44 (RTB-17)	Sample HVD Pole Replacement Costs; and
Exhibit A-45 (RTB-18)	2018 Electric System Loss Study Report.

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

A. Yes.

I. EXECUTIVE SUMMARY

Q. What are the key objectives for the Company's electric distribution system?

A. The Company defined five key objectives for its electric distribution system when it filed its Electric Distribution Infrastructure Investment Plan ("EDIIP") in March 2018 in Case No. U-17990. Those five objectives are safety and security, reliability, system cost, sustainability, and control.

Q. How does the Company pursue these objectives?

A. The Company pursues these objectives through its long-term electric strategy, which focuses on two key areas – excelling at the basics and building for the future (i.e., modernizing the electric grid). When considering the electric distribution system, "excelling at the basics" consists of investment in and maintenance of core traditional infrastructure, like poles, wires, and substations. "Building for the future" consists of enabling the transition to cleaner energy resources, including integration of distributed energy resources ("DERs"), and increasing automation of the system, through the use of advanced grid technologies.

Q. What foundational plans underpin the Company's electric strategy?

A. The Company developed two foundational plans underpinning its electric strategy in 2018. The first was the EDIIP, which was the Company's five-year plan for electric distribution investments. The second was the Company's IRP, which was filed and approved in Case No. U-20165. The Company's IRP established the Company's long-term Clean Energy Plan, which includes significant investment in distributed solar generation in future years.

These longer-term plans provide a solid starting point for how the Company plans for the future of its electric distribution system.

Q. Beyond the solid starting points established in the EDIIP and IRP, what else does the Company need to do to deliver on its objectives for its electric distribution system?

A. Additional capital investments and maintenance spending are needed to maintain and improve reliability of the electric distribution system. Many assets on the system are aging beyond their expected operating lives, and the system is experiencing increased deterioration, resulting in increased vulnerability to wind and storms – thereby negatively impacting customers by degrading or reducing reliability. Current capital investment and maintenance spending levels are insufficient to address deterioration. Additionally, the Company is experiencing increased demand from customers to connect new homes and businesses to the distribution system, and to relocate distribution assets for various customer projects, necessitating increased Company capital investment in those areas as well.

Q. How does the Company intend to respond to these issues?

A. The electric distribution system plan reflected in my direct testimony begins with the baseline established by the EDIIP, but this plan has evolved to reflect the need for accelerated reliability investments; for more investments to respond to emergent customer requests; and for more investments in grid modernization and other technologies to facilitate the Company's IRP through interconnection of distributed solar generation and other future DER integration. This plan reflects the Company's observations that when the Company completes work on a given circuit, substation, or other part of the distribution system, clear benefits are seen in that area, as I will discuss later in my direct testimony when discussing specific capital investment programs.

Q. What does the electric distribution plan in this filing propose to do?

A. In this filing, the Company is proposing to invest $722,675,000 in capital projects on the distribution system, and to spend $254,744,000 on operations and maintenance ("O&M") on the distribution system. This O&M spending includes programs related to forestry, as discussed by Company witness Chris A. Shellberg, and to service restoration, as discussed by Company witness Brenda L. Houtz, both of which will contribute to the Company meeting its electric distribution objectives.

Q. What will this investment and maintenance in the Company's electric distribution system deliver for customers?

A. This investment and maintenance will primarily benefit customers by improving reliability, putting the Company on a glidepath to a System Average Interruption Duration Index ("SAIDI") of 170 minutes, excluding Major Event Days ("MEDs"), by 2025. In doing so, the Company will replace or rehabilitate grid assets that have deteriorated, including assets that have exceeded their expected lifespan. The Company will remain committed to public and employee safety, with many investments intended to directly improve safety. Finally, the Company will also invest in modernizing its grid through increased system automation and advanced technology, which will improve reliability while also improving efficiency and preparing the system to accommodate DERs in the future.

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 two subsystems: High Voltage Distribution ("HVD") and Low Voltage Distribution ("LVD"). Consumers Energy's HVD system consists nearly entirely of 46 kV lines (96% of the total HVD miles), and also includes radial 138 kV and 69 kV lines (4% and <1% of the total HVD miles, respectively). The HVD system voltage is stepped down, or reduced, at LVD substation transformers onto the LVD system, which includes primary voltages between 2.4 kV and 24.9 kV (grounded-wye and delta). LVD voltage is then further stepped down at the distribution pole-top or padmount transformer to a secondary voltage, serving businesses and residences at voltages between 120 volts and 480 volts. The Company's system has over 2,000 LVD circuits serving its 1.8 million electric customers. A circuit is a combination of electrical devices and hardware that are connected together and emanate from an LVD substation to deliver electrical energy to customers, operating at a defined nominal voltage.

Q. Please provide an overview of the LVD system.

A. The LVD system is comprised of over 66,000 total miles of lines, with approximately 56,000 of those miles being overhead, and over 10,000 of those miles being underground. The LVD system consists of 13 different voltages because the Company acquired several distribution systems from smaller distribution companies over its history. The LVD system also includes a distinct component called the Metro system.

Q. Please explain the nature of the Metro system.

A. The Metro system provides underground distribution service in the downtown areas of six cities in the Company's service territory: Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw. Historically, planning for the Metro system was divided among multiple organizations within the Company. In February 2017, the Company created a new Metro planning group to focus solely on these key downtown areas, reflecting the Company's commitment to investment in Michigan by dedicating specific attention to these areas of economic growth. The Metro planning group has responsibility for the Metro New Business, Metro Demand Failures, Metro Reliability, Metro Rehabilitation, and Metro Asset Relocations sub-programs discussed later in my direct testimony.

Q. Please provide an overview of the HVD system.

A. The electric HVD system is the electric grid from the point of interconnection with the transmission provider through the point at which LVD lines exit LVD substations. It is comprised of and represented by three distinct networks: (i) HVD substations; (ii) HVD lines; and (iii) LVD substations. LVD substations are included as part of the HVD system in order to leverage substation planning, engineering expertise, and large equipment resourcing in a consistent and efficient manner.

Q. Please describe the Company's HVD substation network.

A. The Company's HVD substation network consists of approximately 180 substation locations that contain HVD assets. This is comprised of approximately 120 substations with 138 kV to 46 kV transformation and approximately 60 substation locations that contain Company-owned 46 kV breakers but have LVD or customer transformers or are switching stations.

Q. Please describe the Company's HVD lines network.

A. The Company's HVD lines network consists nearly entirely of 46 kV lines (96% of the total), but also includes radial 138 kV and 69 kV lines (4% and <1% respectively). The

HVD system is comprised of approximately 4,600 total miles, with approximately 4,400 of those miles being 46 kV and 69 kV overhead lines and 19 miles being 46 kV underground lines; and approximately 200 miles being 138 kV overhead lines and four miles being 138 kV underground lines.

Q. Please describe the Company's LVD substation network.

A. The LVD substation network consists of almost 1,100 substations. This is comprised of 783 general distribution substations, 230 Consumers Energy-owned dedicated customer substations, 35 customer-owned dedicated substations, 5 Consumers Energy-owned substations providing wholesale distribution service to rural co-op and municipal systems, and 30 customer-owned substations providing wholesale distribution service to rural co-op and municipal systems.

Q. Please provide a high-level description of how the HVD substations, HVD lines, and LVD substations function together as the electric HVD system.

A. The HVD substations are sourced at 138 kV by connections to the transmission system. These HVD substations contain transformers that step down the voltage from 138 kV to 46 kV. Exiting these HVD substations are HVD 46 kV lines which provide the source of voltage to LVD substations, which then step the 46 kV HVD voltage down to primary voltages between 2,400 and 24,900 volts. Other LVD substations connect through 69 kV or 138 kV HVD lines to the transmission system. These LVD substations also step the HVD voltage down to primary voltages between 2,400 and 24,900 volts. The three networks are comprised of various components such as wood and steel poles, steel towers, substations, and overhead and underground wires.

Q. Please describe the importance of the HVD system.

A. The HVD system is the foundation and source for the LVD system. Simply put, the LVD system cannot function without the HVD system as its source. While distinct, these three components of the HVD system work in an integrated manner to safely and reliably deliver electricity to the customers the Company serves.

Q. What are the primary differences between the HVD and LVD systems, and why does that affect investment planning at the Company?

A. In addition to the differences in voltages mentioned previously, the HVD and LVD systems are on different planning cycles due to types of components used and the relative scope and size that each makes up as part of the Company's overall distribution system. The LVD system comprises a larger part of the overall distribution system asset base, is affected differently by vegetation and storms compared to the HVD system, has assets with different life cycles, and is treated differently by the Company's accounting rules.

Q. How do the differences in accounting rules affect LVD and HVD?

A. Because the Company accounts for LVD assets on a mass property basis, it has less age of asset detail for the LVD system than for the HVD system. Therefore, it is particularly important to have inspection programs in place that monitor system health. The Company uses these programs to approximate the overall system condition.

III. ELECTRIC DISTRIBUTION SYSTEM: STRATEGY

Q. Please explain each of the five objectives for the Company's electric distribution system.

A. As noted in the Executive Summary section of my direct testimony, in March 2018 the Company defined five key objectives for its electric distribution system in its EDIIP filing. Those five objectives, which are still applicable today, are:

- Enhance cybersecurity, physical security, and safety: Introduce new technologies and new work processes to support the deployment and operation of those technologies, designing the system to ensure that security and safety of customers and employees are maintained and ultimately enhanced;
- Improve reliability and resilience: Harden the system where necessary, improve system visibility to more proactively operate the system, minimize outages, respond with speed and effectiveness to minimize outage duration, and better manage voltage;
- Optimize system cost over the long term: Meet objectives in a manner that is most cost-effective and equitable for the entire customer base over the long term;
- Increase sustainability and reduce waste in the system: Reduce waste by building more modular and targeted investments and explore opportunities to promote lower carbon resources where economical, such as through non-wires alternatives to integrated distributed generation; and
- Enable greater control: Configure the system to provide customers with data, technology, and tools to take greater control over energy supply and consumption, using a more robust communications network to facilitate two-way flows of information.

Q. How do these objectives affect the Company's LVD and HVD system planning?

A. At a high level, through its planning process, the Company prioritizes its investments to best achieve its long-term objectives. The Company first determines and dedicates the capital investments needed to respond to the emergent needs of customers. It then conducts a thorough analysis of the state of the system to determine how to best allocate funds, using a variety of investment prioritization methodologies. The Company also considers available personnel and other resources to complete necessary engineering and field work to ensure that identified investments can be completed. Throughout the year, the Company uses collaborative processes to continuously assess and improve performance and to respond to changes in customer needs. The Company integrates a robust and evolving set of design standards when planning projects and is more fully integrating its processes to consider non-wires solutions as well as traditional infrastructure investments. It is important to note that both LVD and HVD system work and corresponding investment needs can be affected significantly by requests external to the Company, as is the case with asset relocation and new business work.

Q. Does the Company's electric distribution strategy remain the same as when the 2018 EDIIP was filed?

A. In general, yes. The Company remains focused on the five objectives, discussed above, that were enumerated in the 2018 EDIIP. However, the Company is proposing to increase its electric distribution capital investments in certain key areas in this filing compared to the investment levels that the Company identified in the 2018 EDIIP. The Company is projecting to invest larger amounts in some of its New Business and Asset Relocations sub-program areas, as will be discussed in greater detail later in my direct testimony. Furthermore, the Company is proposing to invest larger amounts in some of its Reliability sub-program areas. This will also be discussed in greater detail later in my direct testimony. In broad terms, the Company has identified additional investment needs in order to address system deterioration and more effectively improve reliability, compared to the investment needs identified in the EDIIP.

Q. Are there any other factors that govern the Company's electric distribution strategy?

A. Yes. As mentioned in the Executive Summary section of my direct testimony, the Company is also building for the future of the electric distribution grid. The Company's 2018 IRP included a plan to heavily invest in distributed solar generation to help meet generation capacity needs while significantly reducing the use of fossil fuels. The IRP also relied on the use of conservation voltage reduction ("CVR," discussed in greater detail later in my direct testimony) to reduce generation needs as a means of addressing the Company's electric capacity requirements. The Company is also planning, in general, for greater expansion of DERs, including third party-owned generation and utility and third party-owned storage. All of these factors drive the Company's strategy surrounding new technologies and analytics, which will be discussed in more detail in the section of my direct testimony covering Grid Modernization.

Q. How does the Company measure reliability?

A. The Company considers a number of reliability metrics, with SAIDI being the most prominent.

Q. Why does the Company focus on SAIDI as part of its electric distribution spending?

A. The importance of SAIDI performance – and the performance of SAIDI's constituent parts, System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") – was emphasized in a September 1, 2009 Report addressed to the Michigan State Legislature, submitted on behalf of the MPSC in accordance with Section 10p of 2008 Public Act 286, MCL 460.10p, where it was stated:

> In light of the research Staff conducted, the Commission finds that Consumers Energy and Detroit Edison at this time should include SAIDI, SAIFI, and CAIDI reporting (with and without major events) on a rolling five year average in a

> new docket that will be opened by the Commission. These indices have been proven to show the reliability of electricity in a utility's power system and are useful to the Commission in identifying utility performance trends for each specific utility on a going forward basis. The intent of the information is not to benchmark the utilities nationwide or within the state, but rather to measure performance levels of each utility against its own historical data.

Additionally, in accordance with the September 15, 2009 Order in Case No. U-16066 and a subsequent Order in the same docket on January 23, 2014, the Company provides the MPSC annual performance information related to SAIFI, CAIDI, and SAIDI with and without major events, on a rolling five-year average basis, using the industry standard Institute of Electrical and Electronics Engineers ("IEEE") method of calculation.

Q. What SAIDI performance level will be produced through the spending outlined in this rate case?

A. The Company estimates that the spending levels outlined in this case will put the Company on a glidepath to a SAIDI performance of approximately 170 minutes, excluding MEDs, by 2025, a reduction of 28 minutes from the 2020 projected performance of 198 minutes. This glidepath is supported by the distribution capital investments and O&M spending discussed in detail in my direct testimony and is also supported by the robust Forestry plan discussed by Company witness Shellberg.

Q. How is this SAIDI glidepath broken down?

A. The Company's SAIDI glidepath is based on modeled improvements to both SAIFI and CAIDI. Beginning with projected performance in 2020, the modeled SAIFI and CAIDI improvements are shown in Figure 1 below. These figures are net of ongoing deterioration, because a certain amount of investment is necessary to keep up with deterioration and prevent performance from worsening.

FIGURE 1
RELIABILITY PERFORMANCE GLIDEPATH

	2020	2021	2022	2023	2024	2025
Net SAIFI	1.009	1.001	0.978	0.955	0.936	0.920
Net CAIDI	196.6	194.1	191.2	189.2	187.1	184.4
Net SAIDI	198	194	187	181	175	170

Q. What Company investments and activities will support this improvement in SAIFI?

A. The Company has modeled that certain investments and activities proposed in this filing will affect SAIFI, as shown in Figure 2 below. These figures are also net of ongoing deterioration. In some areas, shown in red as negative numbers, the Company's investments and activities will drive a net reduction in SAIFI over the glidepath period. In other areas, shown in black as positive numbers, SAIFI will actually increase on net due to deterioration; however, the Company's investments in these areas are still necessary to prevent SAIFI from getting even worse. The figures shown for each year are cumulative, not incremental.

FIGURE 2
SAIFI GLIDEPATH BY INVESTMENT/ACTIVITY AREA

Program/Sub-program	Investment Category	2021	2022	2023	2024	2025
Forestry		(0.016)	(0.03)	(0.049)	(0.065)	(0.081)
LVD Lines Rehabilitation	Security Assessment Repairs	0.019	0.027	0.036	0.047	0.059
LVD Lines Reliability	Targeted Circuit Improvements	(0.002)	(0.006)	(0.011)	(0.016)	(0.021)
	LVD Pole Replacements	0.005	0.010	0.015	0.019	0.024
Grid Modernization	ATR Loops	(0.013)	(0.024)	(0.033)	(0.041)	(0.047)
HVD Lines Reliability	HVD Pole Replacements	0.001	0.002	0.002	0.002	0.003
	HVD Pole Top Rehabs	(0.000)	(0.001)	(0.001)	(0.001)	(0.001)
	HVD Line Rebuilds	(0.004)	(0.009)	(0.017)	(0.024)	(0.031)
Secondary Improvements		0.001	0.002	0.003	0.004	0.005

Q. What Company investments and activities will support the CAIDI glidepath?

A. The Company has modeled that certain investments and activities proposed in this filing will affect CAIDI, as shown in Figure 3 below. These figures are net of ongoing deterioration, and are cumulative for each year, not incremental.

FIGURE 3
CAIDI GLIDEPATH BY INVESTMENT/ACTIVITY AREA

	2021	2022	2023	2024	2025
New Tawas Service Center	(0.37)	(0.37)	(0.37)	(0.37)	(0.37)
ADMS	(0.45)	(0.91)	(1.37)	(1.83)	(2.28)
DSCADA	(1.10)	(2.06)	(2.06)	(2.06)	(2.06)
Reduced Crew Workload	(0.36	(1.49)	(2.55)	(3.45)	(4.33)
Forestry	(0.24)	(0.57)	(1.05)	(1.81)	(3.17)

As the number of outages is reduced, crews will have fewer outages to respond to; this reduction in workload will allow crews to more quickly address outages that do occur. This will produce CAIDI savings represented by the Reduced Crew Workload line item above.

Q. Why is the Company's SAIDI target in this filing different from its 2018 EDIIP SAIDI target of 120 minutes by 2022?

A. When the Company was developing the 2018 EDIIP, it did not have a comprehensive and accurate gauge of overall system condition, particularly for LVD assets. This made it difficult to accurately account for existing system deterioration in the 2018 EDIIP when estimating future SAIDI projections. As noted in the Electric Distribution System Overview section of my direct testimony, LVD assets have been treated on a mass property accounting basis, which makes it more difficult to assess LVD system age. The Company is enhancing its distribution asset management capabilities, as discussed later in my direct testimony, to address this issue going forward. Even as the Company's distribution asset management capabilities remain under development, the Company has learned more since the 2018 EDIIP was filed regarding system deterioration levels; this is particularly illustrated by system performance in adverse weather conditions, as discussed in detail below. Additionally, the Company has quickly increased its visibility into the state of the LVD system through its Grid Modernization technological enhancements, giving the Company insights it did not previously have.

While system deterioration largely impacts SAIFI, by increasing the total number of interruptions to customers, deterioration also increases CAIDI. As deterioration increases, repairs take longer, increasing outage durations. For example, when lines, poles, and cross-arms are in good condition, they can withstand tree contact and adverse weather with limited damage, but as the assets deteriorate, susceptibility to damage increases. When deterioration is limited, repairs following a tree strike may only involve removing the tree and repairing an insulator; as deterioration progresses, the repair may also expand to include replacing the cross-arm and pole, or even adjacent facilities.

Q. Given the size of the Company's electric distribution system, what is the full scope of capital investment needed to address all reliability needs on the system?

A. Figure 4 below illustrates the levels of capital investment in the electric distribution system under three different scenarios: (i) actual projected 2019 spending; (ii) projected 2021 test year spending; and (iii) annual investments needed to break even against system deterioration, as defined by replacing assets when they reach the end of their lifecycle. Each scenario requires a certain amount of Forestry O&M spending, a topic discussed by Company witness Shellberg. The capital investment dollars shown in each scenario do not include annual investments in other distribution programs, such as New Business, Asset Relocations, and others. It is also important to note that, when the Company filed the 2018 EDIIP, it estimated that the full cost to replace every asset that is beyond its expected lifespan would be approximately $4,500,000,000.

Figure 4
Capital Investment Scenarios

Category	Units	SAIDI 2019 Actual Minutes	2019		2021		Breakeven Deterioration	
			Annual Spend	Equiv Units/Yr	Annual Spend	Equiv Units/Yr	Annual Spend	Equiv Units/Yr
Forestry (O&M)	56,000 LVD Miles 4,600 HVD Miles	95	$53M	3,106 LVD O&M Miles 1,064 HVD O&M Miles	$84M	5,223 LVD O&M Miles 1,125 HVD O&M Miles	$120M	8,000 LVD O&M Miles 1,100 HVD O&M Miles
LVD Lines Overhead (OH)	60-Yr Life 56,000 Miles	99	$69M	278 miles	$104M	419 Miles	$231M	933 Miles
LVD Lines Underground (UG)	40-Yr Life 10,000 Miles		$4M	11 miles	$6M	16 Miles	$94M	250 Miles
HVD Lines	70-Yr Life 4,600 Miles	23	$48M	107 miles	$88M	196 Miles	$30M	66 Miles
LVD Substations	50-Yr Life 1,100 Subs	9	$25M	18 subs	$44M	31 Subs	$31M	22 Subs
HVD Substations	70-Yr Life 120 Subs	5	$5M	0.4 Subs	$34M	2 Subs	$42M	3 Subs
Total		**231***	**$151M (Capital)**		**$276M (Capital)**		**$428M (Capital)**	

*Not including 3 SAIDI minutes associated with ITC Holdings Corp. ("ITC")-owned transmission system

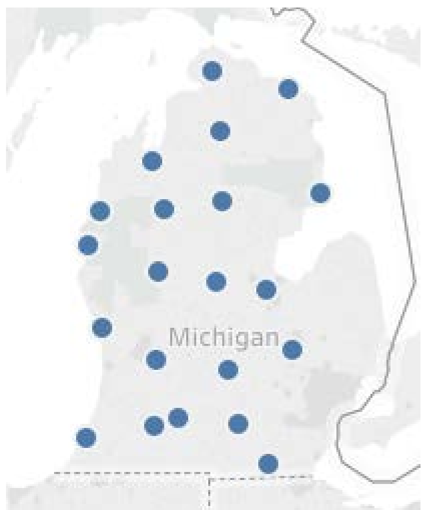
Q. Is the Company proposing to spend at levels identified in the breakeven columns in this filing?

A. No. This table illustrates the full level of annual investment that would be needed to address reliability needs on a large enough percentage of the distribution system to keep up with system deterioration. Human and material resource constraints would prevent the Company from spending at this level, or completing this associated volume of work, in the 2021 test year.

Q. How does the Company substantiate its assumptions regarding system deterioration?

A. One of the clearest indicators of system deterioration comes from system performance during storm conditions. The Company monitors wind speed data from 21 different official National Weather Service ("NWS") stations in Michigan, as shown in Figure 5 below.

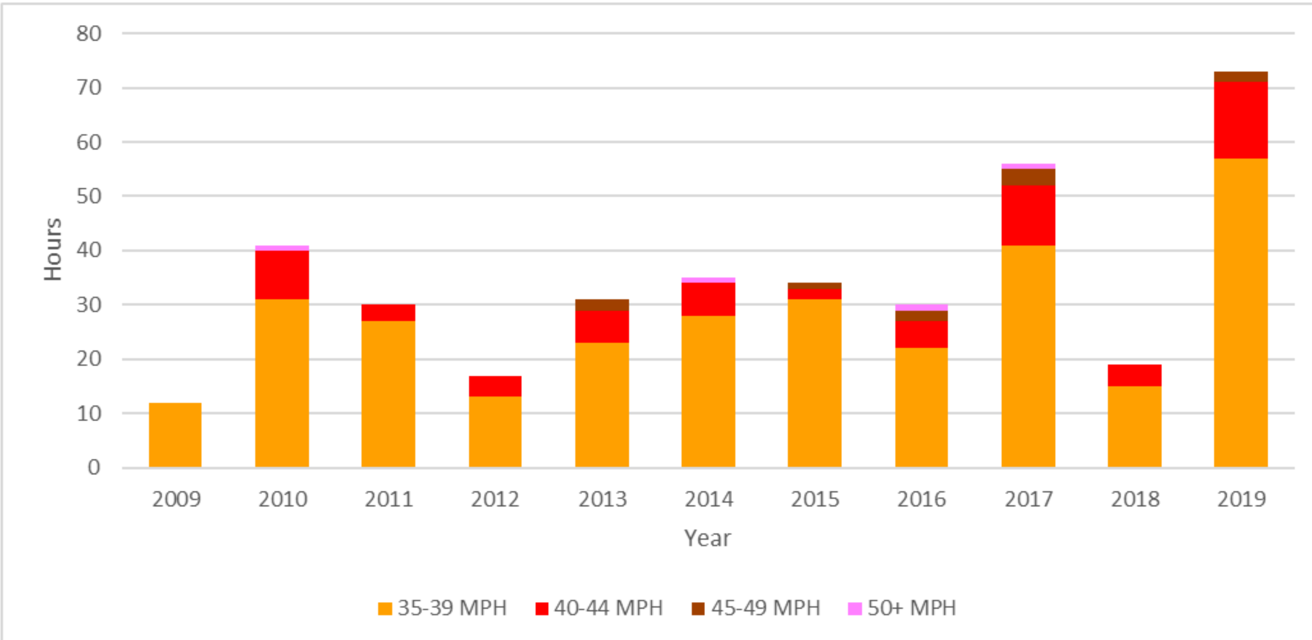
FIGURE 5
OFFICIAL NWS WIND OBSERVATION STATIONS



In recent years, the Company has observed that wind speeds across the system increased in severity. Figure 6 below illustrates the number of hours, aggregated across these 21 observation stations, during which wind speed was sustained at higher than 35 miles per hour. As illustrated, 2019 was the windiest year in recent history, with 2017 the second-windiest.

FIGURE 6

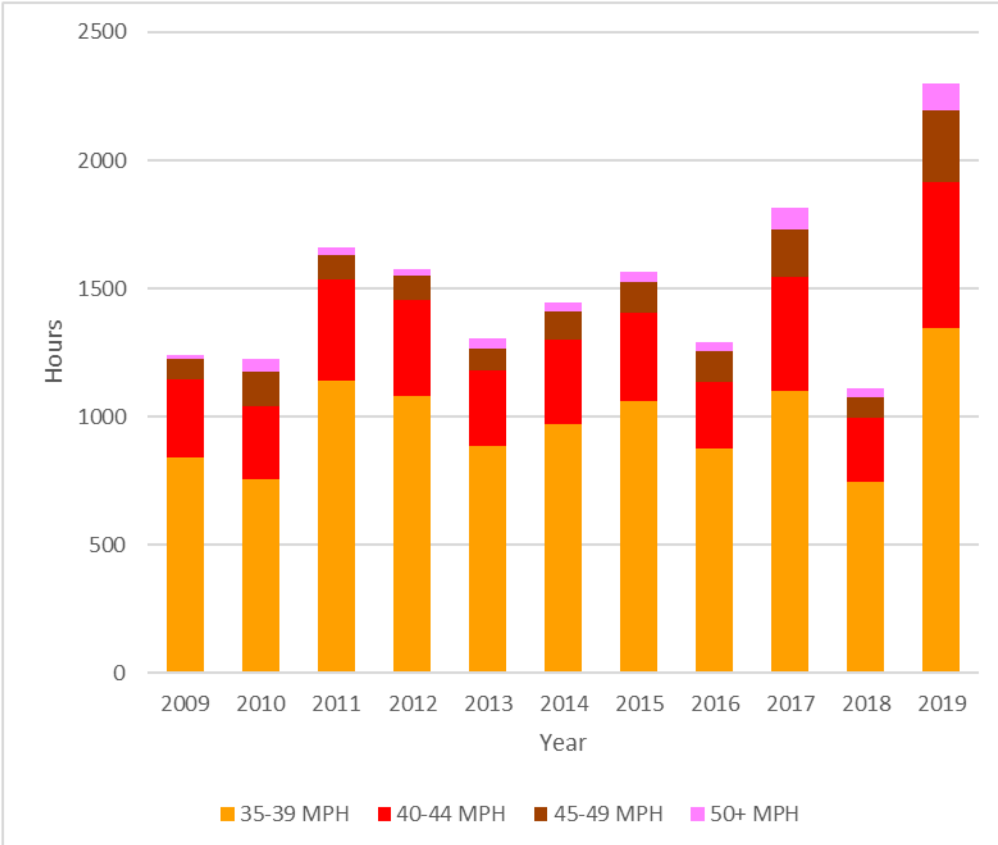
STATION-HOURS EXCEEDING HIGH WIND SPEED THRESHOLDS



In addition to sustained high winds, severe gusts can also cause outages. The NWS observation stations record gusts when there are rapid fluctuations of 10 miles per hour or more between peaks and lulls over a ten-minute window, with the gust speed being the maximum wind speed observed in that window. Figure 7 below illustrates the number of hours, aggregated across the 21 observation stations, during which gusts of more than 35 miles per hour were observed. As illustrated, 2019 was also the gustiest year in the past decade, and 2017 was also severe.

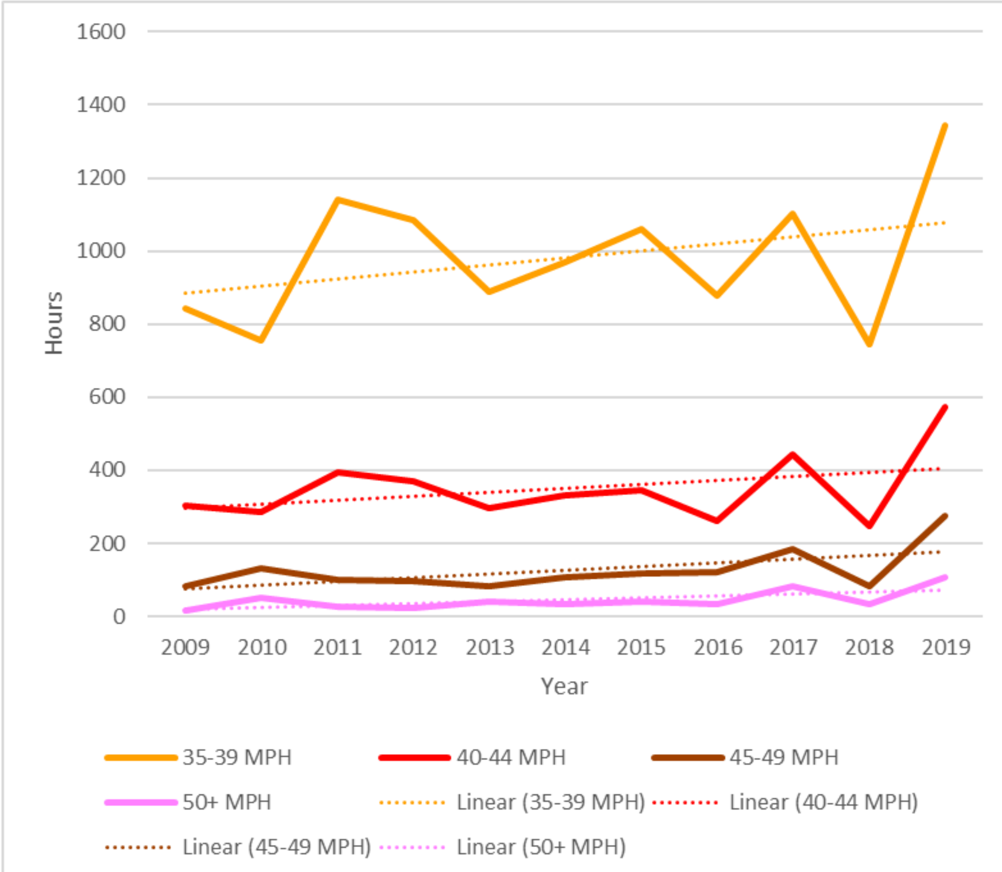
FIGURE 7

STATION-HOURS EXCEEDING HIGH GUST THRESHOLDS



To further illustrate the increasing severity of gusts, Figure 8 below isolates the frequency of gusts exceeding 40 miles per hour. As illustrated, gusts have been becoming more frequent at each of the high-speed bands.

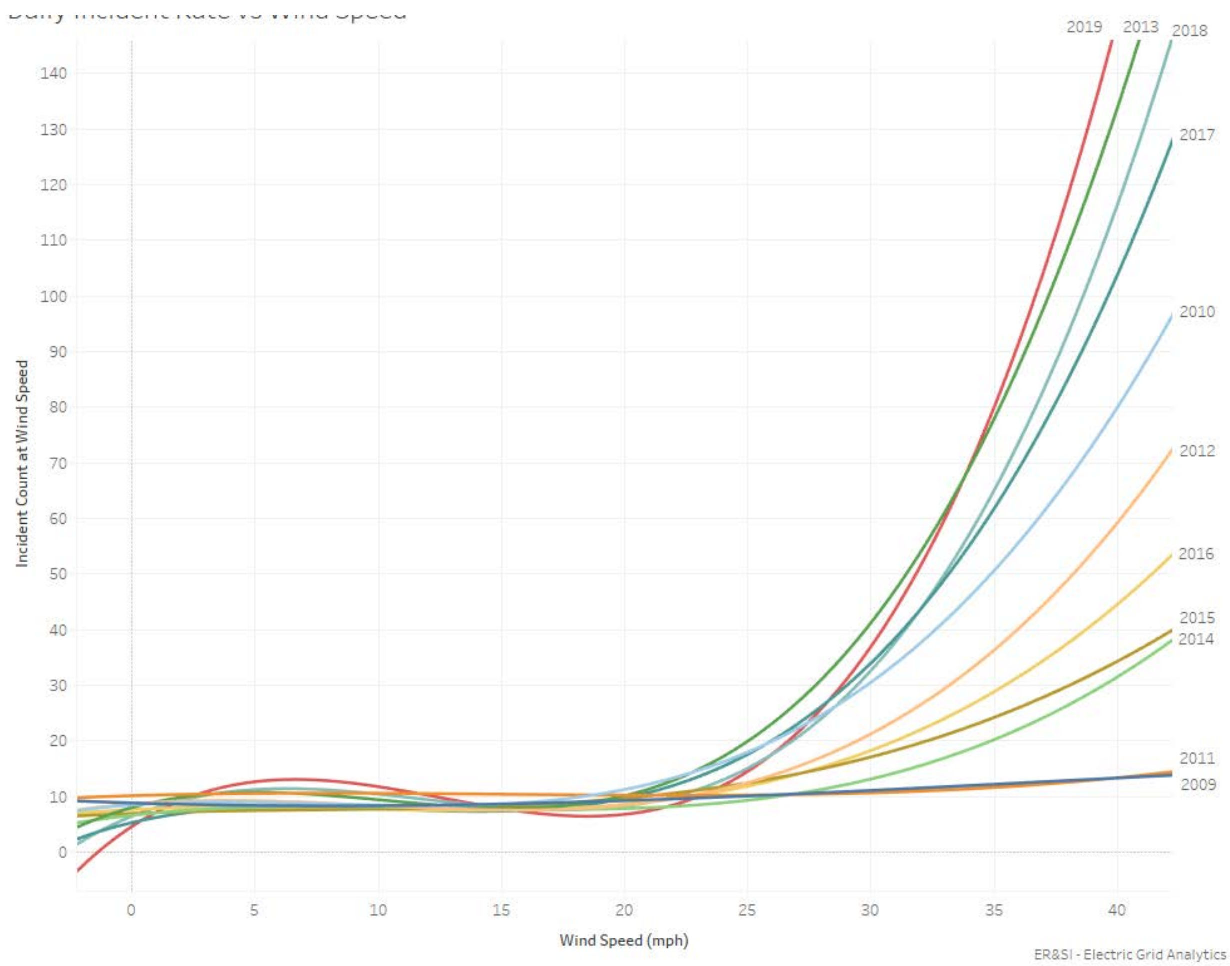
FIGURE 8
STATION-HOURS EXCEEDING HIGH GUST THRESHOLDS



The data shown in Figure 6 through Figure 8 only illustrates that wind speeds have been getting worse. To illustrate system deterioration, the Company has plotted wind speeds against the number of incidents on the system, which is shown in Figure 9 below. "Incident," in this case, is defined as any event in which electric service is interrupted to one or more customers. For each incident on the system, the Company obtained the average wind speed for the hour of the incident from the nearest NWS observation station. To most accurately reflect system deterioration in this data set, all major event days are included, and incidents are counted equally irrespective of the number of customers interrupted.

FIGURE 9

INCIDENT RATE VS WIND SPEED



As shown in this data, once wind speeds begin to exceed approximately 22 miles per hour, incidents tend to increase. This data also shows that, at any given higher wind speed, the number of incidents has been increasing in recent years, with 2017, 2018, and 2019 all among the four worst-performing years since 2009. This trend is indicative of system deterioration – at any given level of adverse weather, the system is less resilient than it was in the past.

Q. Please summarize the Company's approach to SAIDI performance in this filing.

A. When the Company developed its 2018 EDIIP filing, it did not have a comprehensive and accurate gauge of overall system conditions regarding deterioration, affecting the SAIDI projections made in that filing. In addition to deterioration, adverse weather has worsened in recent years, negatively affecting system performance. Consequently, the Company's projected SAIDI performance in this filing is different from that shown in the 2018 EDIIP. The Company's proposed spending in this filing takes better information into account regarding deterioration to systematically reduce SAIDI along a glidepath going forward.

IV. HISTORICAL SYSTEM PERFORMANCE

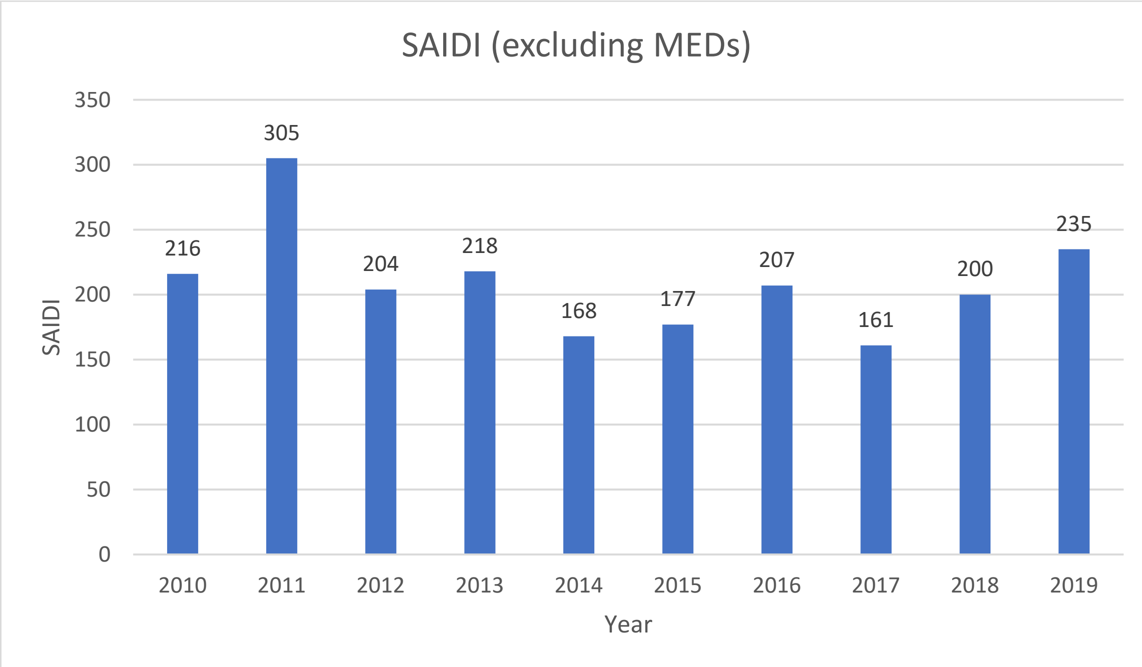
Q. How does the Company evaluate electric distribution system performance?

A. SAIDI is the primary measurement of system reliability used by Consumers Energy (and other utilities) to evaluate electric distribution system reliability. SAIDI is a measurement of the average number of minutes per year that a typical electric customer is without electric service. Additionally, the Company monitors its system reliability performance through utilization of the Commission's Service Quality and Reliability Standards established in Case No. U-12270.

Q. What has been the recent reliability performance of Consumers Energy's distribution system?

A. Figure 10 below shows Consumers Energy's SAIDI results, excluding MEDs, over the period of 2010 through 2019. A MED is a day for which the reliability metrics for outages initiated on that day are excluded from the Company's statistics, in accordance with IEEE Standard 1366-2012, which defines MEDs based on five sequential years of daily outage minutes. MEDs are excluded from these totals to normalize performance data for unusually severe weather. The methodology of determining the level of storm activity to exclude in developing this chart is based on the IEEE Guide for Electric Power Distribution Reliability Indices.

FIGURE 10
CONSUMERS ENERGY SAIDI PERFORMANCE (2010-2019) EXCLUDING MEDs



Q. What are the components of SAIDI?

A. SAIDI is comprised of two components: SAIFI and CAIDI. SAIFI is a measure of frequency of outages, which 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:

SAIDI = SAIFI * CAIDI

Figure 11 shows Consumers Energy's SAIFI results over the period of 2010 through 2019, excluding MEDs.

FIGURE 11
SAIFI (2010-2019) EXCLUDING MEDS

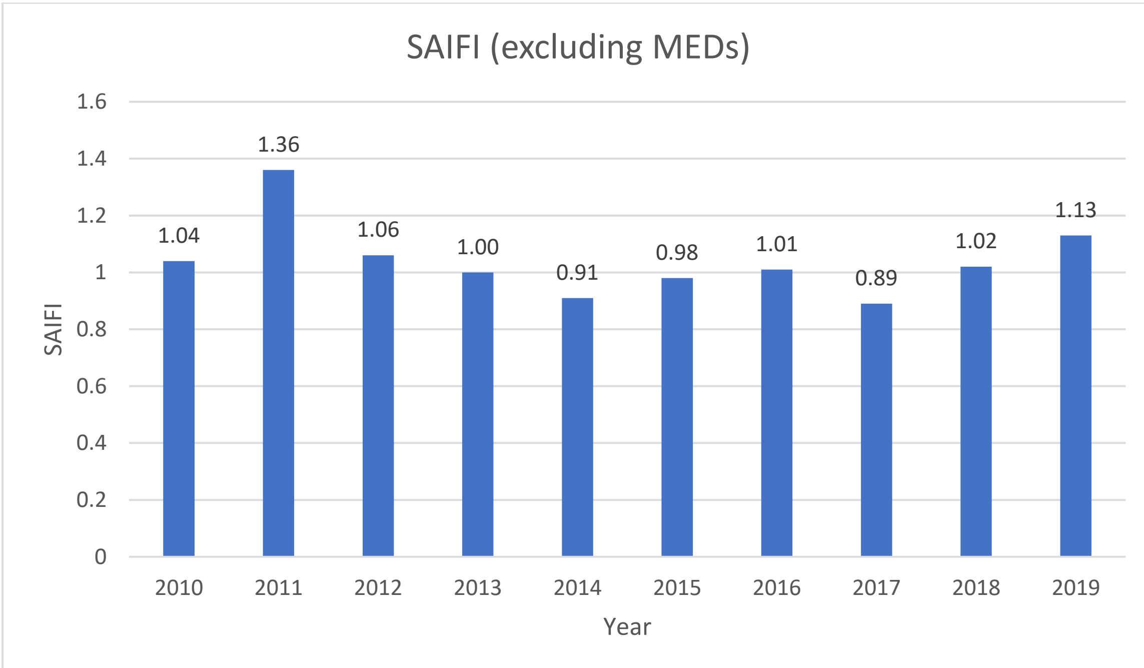
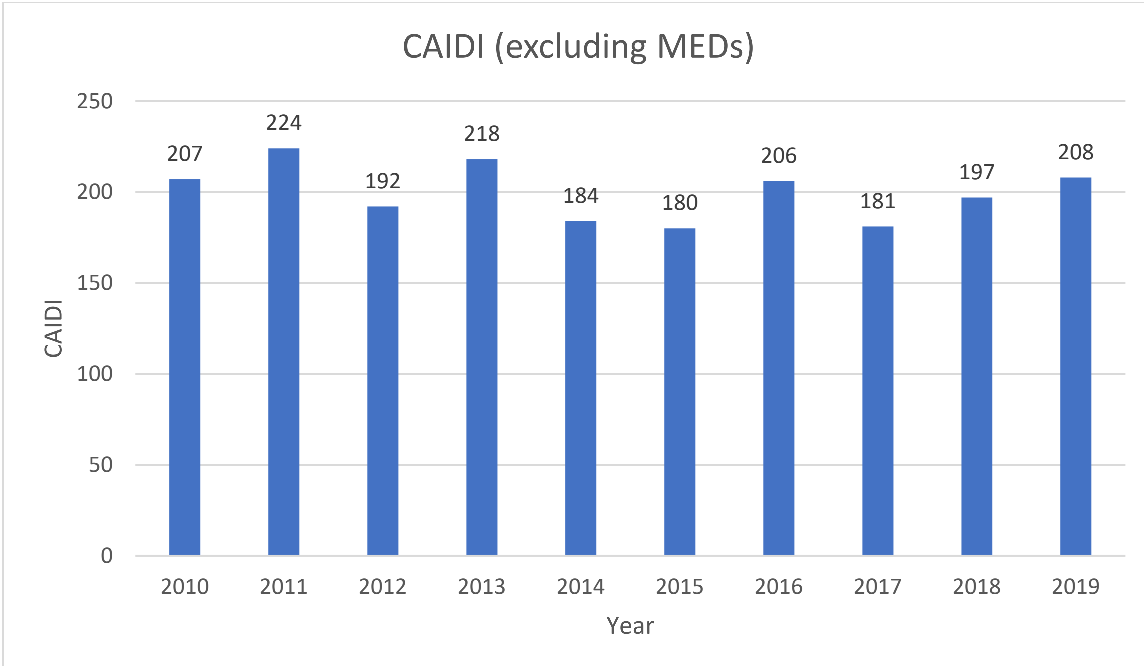


Figure 12 shows Consumers Energy's CAIDI results over the period of 2010 through 2019, excluding MEDs.

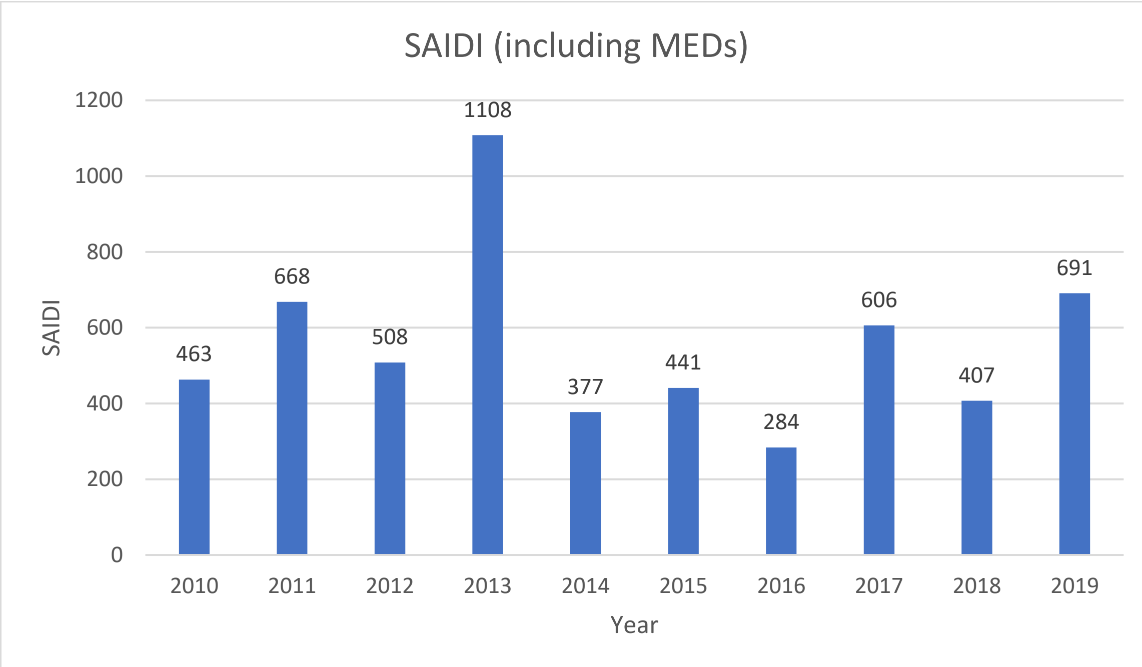
FIGURE 12
CAIDI (2010-2019) EXCLUDING MEDS



Q. If MEDs are *not* excluded, what has been the Company's recent SAIDI performance?

A. The Company's SAIDI results over the period of 2010 through 2019, *including* MEDs, is shown in Figure 13 below.

Figure 13
SAIDI (2010-2019) Including MEDs



Q. Please explain the year-over-year variation in SAIDI when MEDs are included.

A. The year-over-year variation is driven in part by the number of MEDs in a given year, as any MED is likely to result in more customer outages than on a normal day. The number of MEDs in each year from 2010 through 2019 is shown in Figure 14 below. SAIDI is particularly increased during MEDs when the system experiences more than 2,300 outages. Storms in November 2013, December 2013, March 2017, and July 2019 all exceeded this threshold, and all translated into large increases in customer interruption minutes, driving the higher annual SAIDI totals in those years. In most cases, these were multi-day storms that resulted in consecutive MEDs. The number of MEDs over the three-year period of 2017 through 2019 was higher than any other three-year period during the decade, an indicator of worsening weather and deterioration.

FIGURE 14
MEDS PER YEAR, 2010-2019

Year	MED Days
2010	7
2011	6
2012	7
2013	10
2014	4
2015	3
2016	5
2017	8
2018	7
2019	9

Q. Is there a correlation between SAIDI performance and the Commission's Service Quality and Reliability Standards for electric distribution systems?

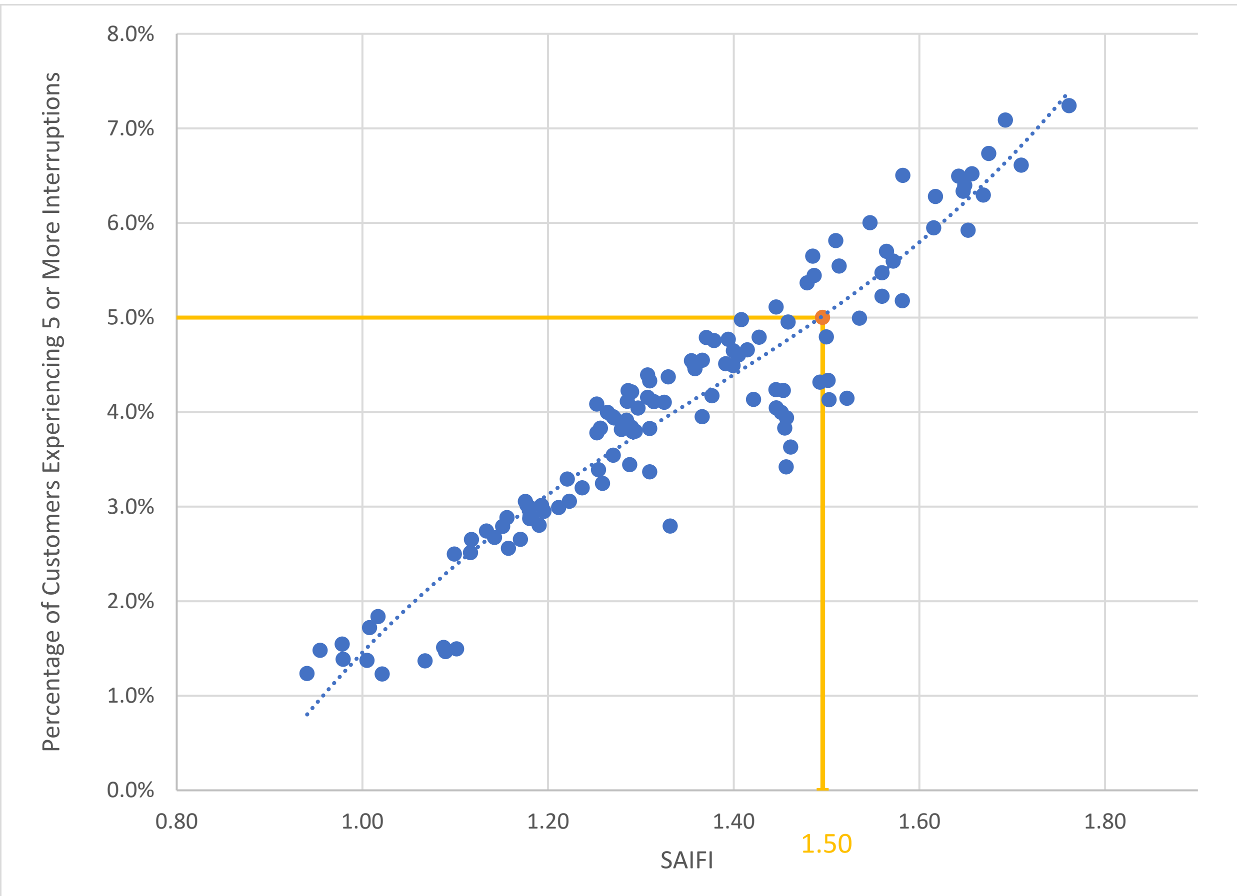
A. Yes, there is. The two components of SAIDI (SAIFI and CAIDI) have a strong correlation with two of the Commission's key Service Quality and Reliability Standards that were adopted in Case No. U-12270, and they strongly influence customer satisfaction. These two standards are the Repetitive Outage performance standard (less than 5% of customers experiencing five or more interruptions in a year), which by definition includes storms, and the Normal Conditions restoration performance standard (more than 90% of customers restored in eight hours during Normal Conditions), as defined by the Commission in those standards.

Q. What Commission performance standard is impacted by SAIFI?

A. There is a correlation between SAIFI (including MEDs) and the Commission's Repetitive Outage performance standard, which does include storms. As SAIFI (including MEDs) increases, it becomes more likely that the Repetitive Outage performance standard (less than 5% of customers experiencing five or more interruptions in a year) will not be met. Figure 15 below illustrates the relationship between SAIFI and Repetitive Outage performance. Deteriorating SAIFI performance would increase the probability that more than 5% of customers would experience five or more outages per year. As the number of outages increase, customer satisfaction declines.

FIGURE 15

% OF CUSTOMERS EXPERIENCING 5 OR MORE INTERRUPTIONS IN A YEAR VS. SAIFI (INCLUDING MEDS)



Q. How is the Company's recent SAIDI performance broken down by subsystem?

A. Figure 16 below provides a breakdown of SAIDI by LVD lines, HVD lines, LVD substations, HVD substations, and transmission (on the ITC-owned transmission system).

FIGURE 16
SAIDI BY SUB-SYSTEM 2014-2019

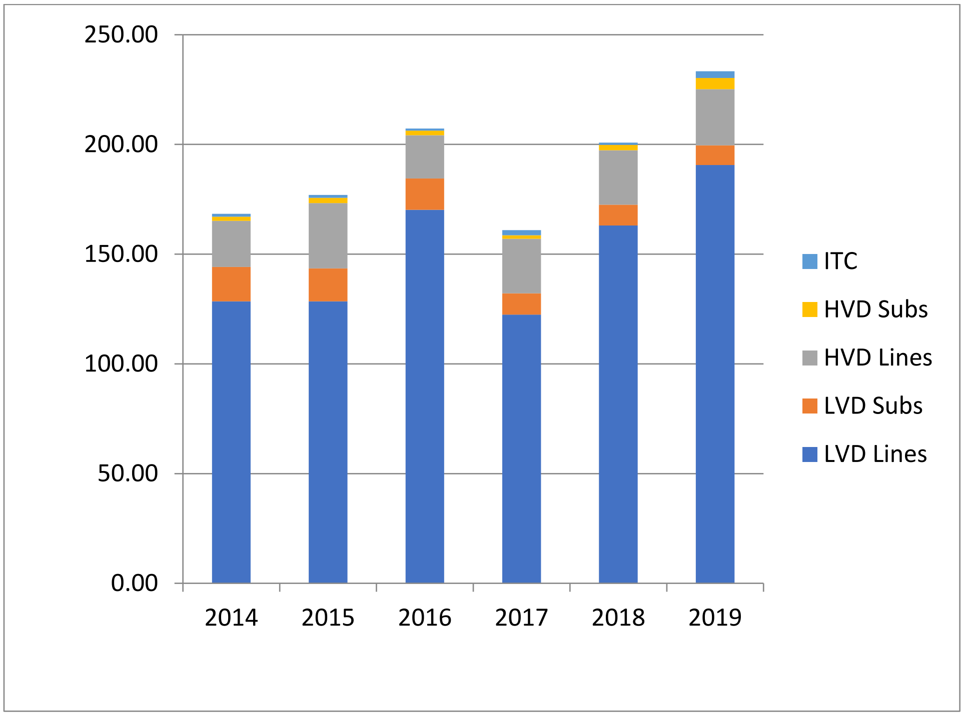


Figure 17 through Figure 19 below show the top causes of outages for the HVD lines, LVD substations, and LVD lines. Figure 17 and Figure 19 illustrate the five-year average for each cause category, and also show the 2019 results for each cause category. Green bars indicate that the 2019 results were better than the five-year average, while red bars indicate that they were worse.

FIGURE 17
HVD LINES SAIDI MINUTES BY OUTAGE TYPE

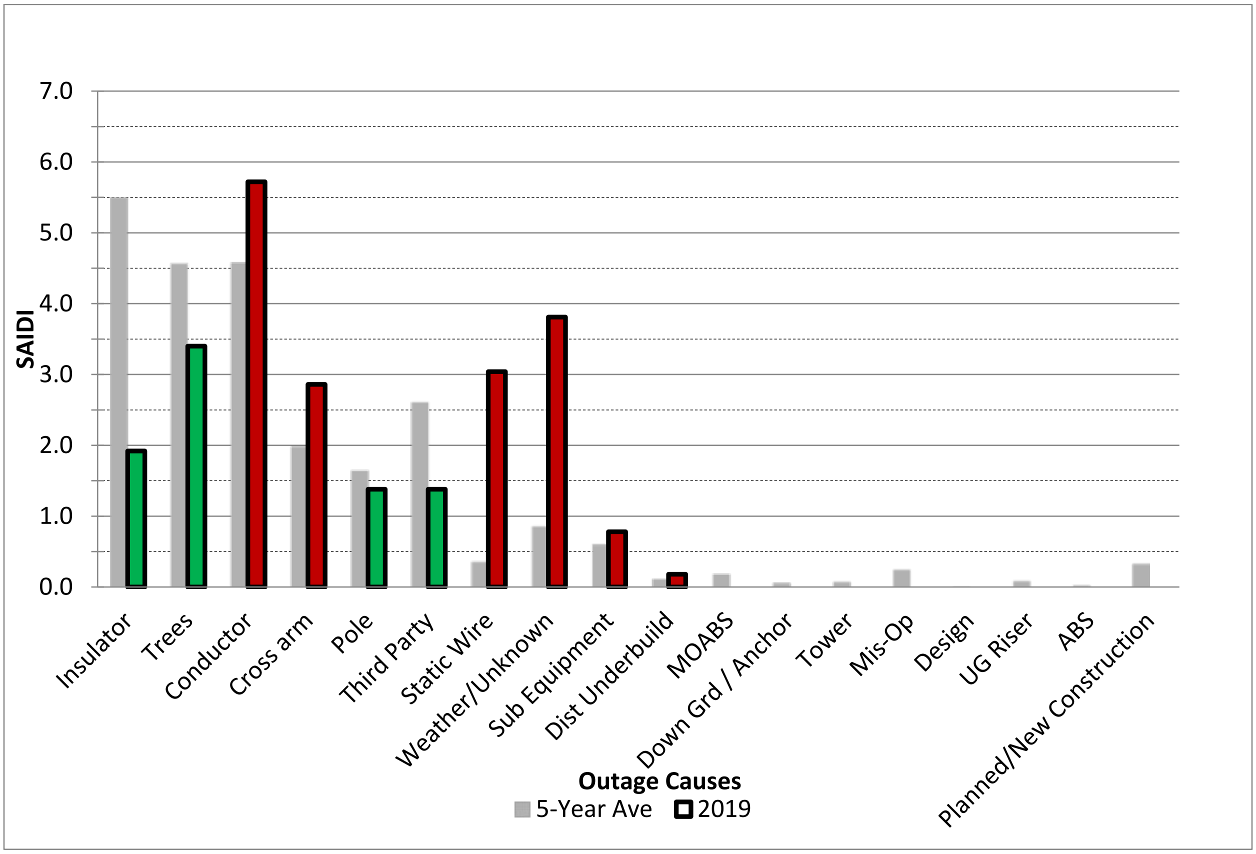


FIGURE 18
LVD LINES INCIDENT CAUSES

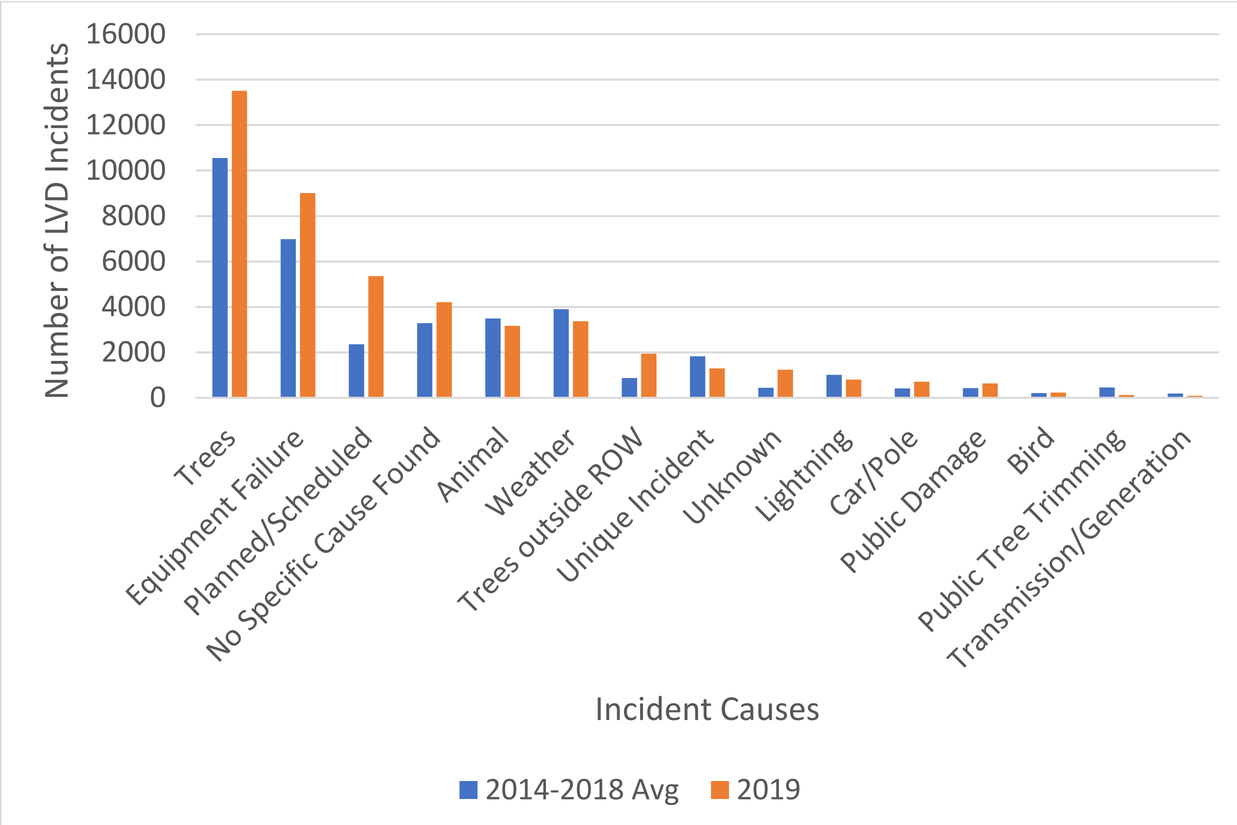
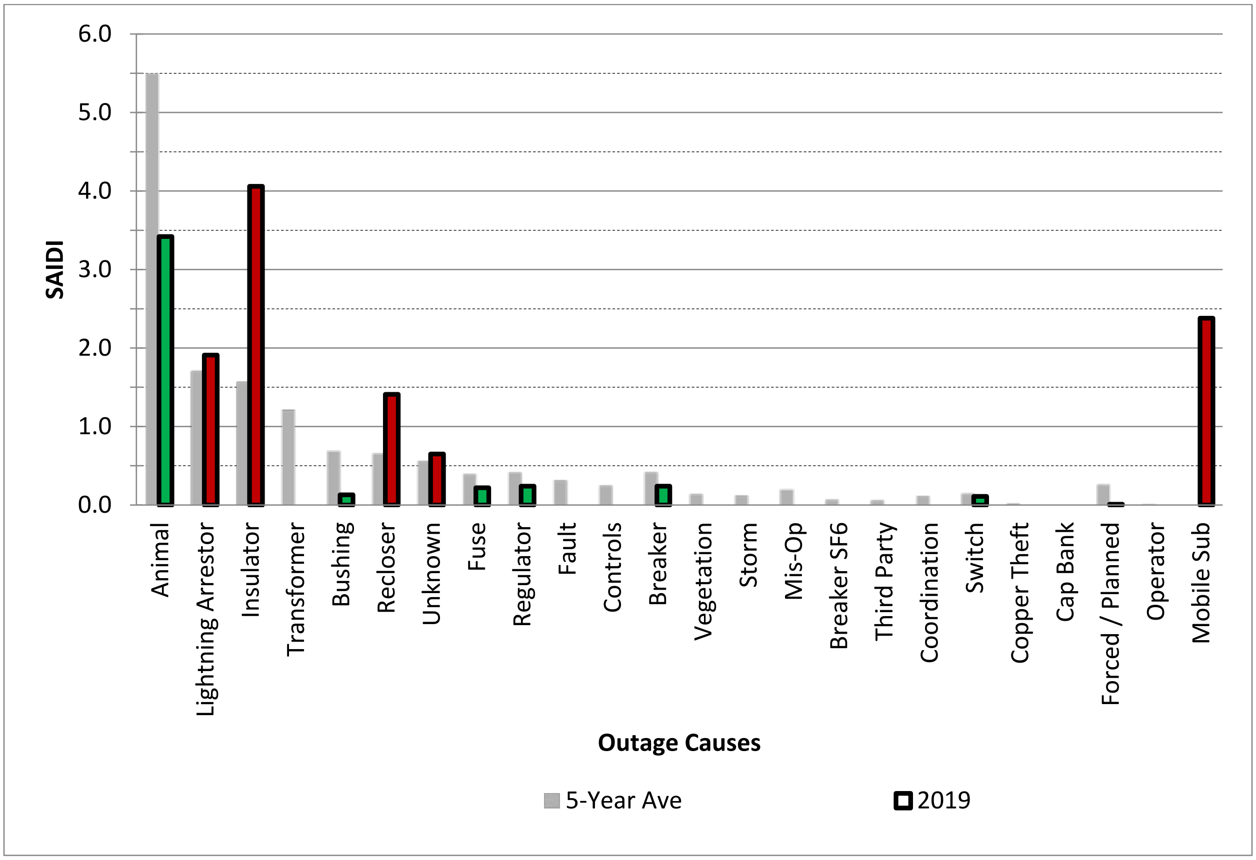


FIGURE 19

LVD SUBSTATIONS SAIDI MINUTES BY OUTAGE TYPE



V. GRID MODERNIZATION STRATEGY

Q. Please define Grid Modernization.

A. Grid Modernization commonly refers to the planned process of investing in grid infrastructure improvements (poles, wires, relays, transformers, etc.) for the utility's electric grid; incorporating new technologies and applications into the electric system to increase reliability; optimizing the delivery system; and facilitating the integration of more diverse energy resources. While many utilities share common themes for defining Grid Modernization, different utilities can have different approaches for implementing and enabling Grid Modernization capabilities due to their unique customer, operational, regulatory, and business needs. Grid Modernization is particularly reliant on robust, secure telecommunications, which supports the growing number of controllable grid devices, added sensors, and increased computational capabilities. As telecommunications architecture continues to evolve, upgrades will be required to support the growing functional and security requirements of Grid Modernization efforts.

Q. Please summarize the Company's Grid Modernization strategy.

A. Over the next five years, the Company is focusing on building three primary advanced grid capabilities:

- Reliability and resilience – Automated re-routing of power flows around an outage and restoration following an outage, commonly known as Fault Location, Isolation, and Service Restoration ("FLISR");
- System efficiency and optimization – Energy efficiency gains and peak reduction through Volt-VAR Optimization ("VVO"), which enables coordinated control of voltage regulators and capacitor banks to reduce system losses and eliminate waste; and CVR, which allows optimization of service-point voltages to reduce energy demand; and
- DER integration – Enabling increased utility ability to coordinate and holistically manage an increasing penetration of DERs on the electric distribution system.

These new capabilities will be enabled through the Company's Grid Modernization investments, building on a foundation of substation automation, communications, and distribution automation standards. The Company will deploy its Advanced Distribution Management System ("ADMS"), enabling deployment of small-scale DERs and DER technologies, and enhance its distribution asset management capabilities.

Q. How does the Company's Grid Modernization strategy support its broader electric strategy?

A. As discussed earlier in the Executive Summary and Electric Distribution Strategy sections of my direct testimony, the Company's electric strategy is focused on the two areas of "excelling at the basics" and "building for the future." Grid Modernization, as a fundamental part of the electric distribution business, is a key element of both of those areas. Targeted Grid Modernization investments in key areas on the distribution system significantly improve reliability and resilience, part of excelling at the basics. Through advanced applications and capabilities, grid modernization enables the utility to make the transition to cleaner energy resources and integration and optimization of DERs, part of building for the future.

Q. How does the Company's Grid Modernization planning align with industry frameworks for grid modernization?

A. Consumers Energy proactively collaborates with other utilities, standards organizations, researchers, and the U.S. Department of Energy ("DOE") and incorporates industry best practices into its Grid Modernization approach. Due to variations in Grid Modernization deployments across North America, the DOE engaged regulators, utilities, energy service firms, researchers, and commercial technology developers to address the critical need for a standardized yet flexible approach for enhancing distribution grid functionality. This effort produced a framework called the Modern Distribution Grid Next Generation Distribution System Platform ("DSPx"). The objective of this project was to provide a useful tool to provide a consistent understanding of the interrelationships of key functions and technology investments to support Grid Modernization goals. The Company's Grid Modernization approach is closely aligned with the DOEs DSPx framework.

Q. How do the foundational components enable new capabilities?

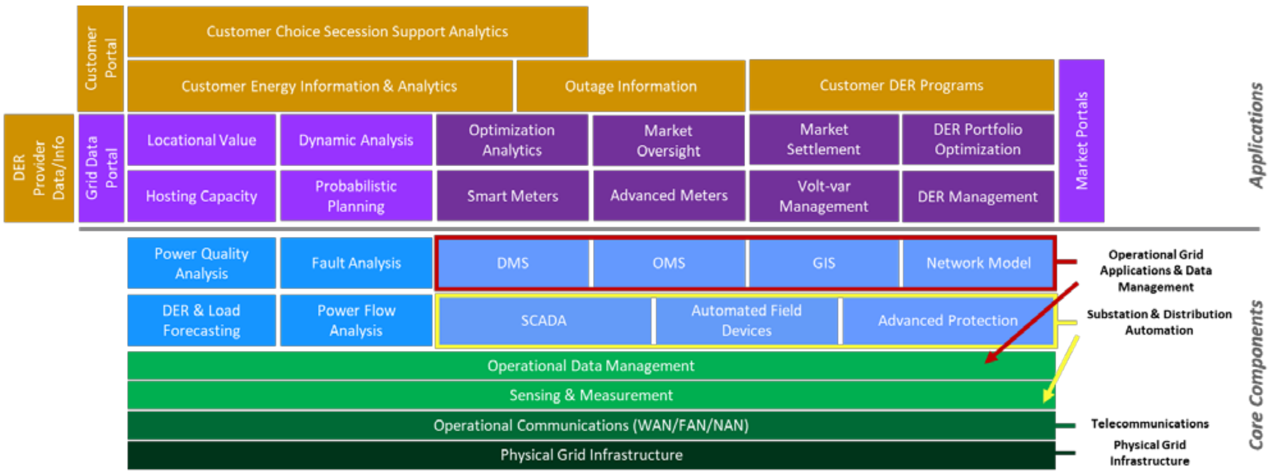
A. The Company's Grid Modernization strategy has included deploying foundational components to provide benefits for the distribution system. These foundational components align with the DOE's DSPx "core components." When foundational components are integrated and work together as a platform, it allows additional applications to be built, providing even greater potential benefits, with both the foundational components and applications working together interdependently. The foundational components are:

- Physical grid infrastructure – poles, wires, transformers, and other grid equipment;
- Telecommunications – wired and wireless network communications and systems to generating facilities, substations, and pole top devices;
- Substation and distribution automation – distribution supervisory control and data acquisition ("DSCADA"), motor operated air brake switches ("MOABS"), automation transfer recloser ("ATR") loops, voltage controllers, and line sensors; and
- Operation grid applications and data management – ADMS, Geographical Information System ("GIS") data, and operational data repositories.

The Company is deploying each of these functional areas through capital investments in a multi-year sequence, scaling deployments of foundational components on the highest benefit areas of the distribution system over time. The Company considers the maturity of technologies in its implementation plan, focusing on larger scale deployments of functional components with known and proven benefits first, with pilots or smaller-scale deployment of technologies still in testing. While each foundational component provides benefits on a standalone basis, all components, when considered together, work interdependently to provide additional benefits through new capabilities. The foundational components are outlined below in Figure 20 to show how these components fit within the DOE's Distribution System Platform.

FIGURE 20

DOE NEXT GENERATION DISTRIBUTION SYSTEM PLATFORM AND APPLICATIONS



Q. What are the Company's plans for DERs in the near-term?

A. In 2020, the Company will be deploying a direct current ("DC")-coupled battery energy storage system ("BESS") attached to a solar generation facility. This DC-coupled battery will allow the solar generation to be dispatchable, as well as potentially provide other services including peak shaving and power quality improvement on the local circuit. In 2021 the Company will deploy a portable BESS to defer a substation upgrade for several years and then be moved to defer a second substation upgrade. The Company plans to complete another BESS in 2022 that will test and demonstrate battery islanding capabilities. In addition to these BESS developments, the Company is exploring other DER opportunities. For example, the Company has been conducting a pilot to test installation of Company-owned residential behind-the-meter batteries on a circuit near Grand Rapids.

Q. What is distribution asset management?

A. Distribution asset management is a strategic and proactive approach for managing electric system assets to minimize life-cycle cost and maximize the life of the assets. Distribution asset management includes an over-arching strategy for technology deployments, and performance improvement across a broad range of key business areas such as system planning, design, construction, operations, and maintenance.

Q. Please explain "technology deployments" for distribution asset management.

A. Technology deployments include new toolsets to enhance accuracy of distribution asset models, and applications and analytics to monitor performance degradation. A complete and accurate electric system model is critical for distribution asset management. To accomplish this, solutions around the design of the asset(s) will be deployed and integrated with the Company's GIS data, illustrating spatial location and relationships with the rest of the network asset model, optimizing design processes. The model itself will be upgraded to the industry standard release (ESRI's Utility Network) to accurately model the entire electric network from generation point to meter. These deployments will also allow the Company to collect and model as-built information to maintain data accuracy after system model changes have occurred. As processes and tools mature for asset data management, the Company will begin to implement asset performance applications and analytics that will access real-time measurement condition and recommend preventative maintenance activities to extend equipment life and reduce downtime.

VI. CAPITAL SPENDING PROGRAMS

A. Capital Spending Overview

Q. What high-level classifications of capital investments does the Company make?

A. The Company makes capital investments under two broad classifications, known as "unplanned" and "planned."

Q. Please describe "unplanned" investments.

A. Several of the Company's capital investment programs respond to demand-driven, customer-driven, or other emergent needs. These investments are not strictly "unplanned" as the Company does anticipate it will have to make these investments, to replace failed equipment and add new customer connections to the system. However, due to the emergent nature of these needs, the Company's investments can be difficult to plan with specificity in advance, because the Company cannot plan for an exact number of equipment failures or new customers, nor where such needs will occur. Instead, the Company generally forecasts the needed investments for these "unplanned" programs based on historical actual expenditures, applying growth rates as appropriate based on external trends. These "unplanned" programs consist of New Business, Demand Failures, and Asset Relocations.

Q. Please describe "planned" investments.

A. In addition to the investments addressing emergent needs described above, the Company also plans investments further in advance to proactively improve the grid through reliability improvement projects, capacity upgrades, and investments in new tools and technology. These programs consist of Reliability, Capacity, and Tools and Technology.

Q. How does the Company's O&M spending relate to its capital investments?

A. The Company's O&M spending supports its long-term capital investments through maintenance and operation of grid infrastructure, plus engineering and design work required to execute projects. It also provides for restoration of service to customers following interruptions. The largest O&M programs that support the reliability of the electric distribution system are Forestry Line Clearing and Service Restoration following interruptions. I discuss numerous O&M programs later in my direct testimony, although

Forestry Line Clearing is discussed by Company witness Shellberg and Service Restoration is discussed by Company witness Houtz.

Q. Given the diverse nature of the distribution capital programs, how does the Company prioritize spending?

A. Specific investment prioritization can vary from program to program, as discussed below in each program's respective section of my direct testimony. Broadly speaking, the Company uses several critical inputs and analyses to aggregate multiple data sources in order to best target and prioritize customer reliability issues to address, identifying specific investments based on the probability of future issues, with customer reliability traditionally measured by SAIDI, SAIFI, and CAIDI.

Q. Has the Company made any recent changes to ensure diversity in its investments?

A. Yes. The Company has developed an approach to consider additional LVD circuit characteristics, beyond those reliability metrics discussed above, to ensure investment across the Company's distribution system and across several of the capital spending programs that I will discuss below. The 2021 test year capital spending plan for these capital spending programs is the first to make full use of this approach. This approach consists of four steps:

- Strategic Direction: Company leadership establishes multi-year goals and broad budget guidance;
- Prioritization: Planners identify circuits for investment in the following two years;
- Solution Options: Planners assess range of solutions to address circuit issues; and
- Investment Plan: An integrated investment plan is produced.

Through this approach, investment decisions may be revised from what simple reliability metrics would normally dictate in several sub-programs, each of which is discussed later in my direct testimony:

- LVD Lines Reliability;
- Metro Reliability;
- LVD Lines Rehabilitation;
- Metro Rehabilitation;
- Grid Modernization; and
- LVD Lines Capacity.

Q. What are the "additional LVD circuit characteristics" considered in this approach?

A. Beyond traditional reliability metrics, the Company also considers geographic characteristics (i.e. circuit line-miles, distance to Company service centers); customer mix; and circuit load and voltages.

Q. What levels of capital spending were authorized by the Commission in the Company's most recent electric rate case?

A. The Commission approved a settlement among the parties in Case No. U-20134. As part of that settlement, the parties agreed on distribution capital spending levels for some of the Company's spending programs. In the Reliability capital program, the Company agreed to spend a minimum of $200,000,000 during 2019. In the New Business capital program, the Company was authorized to spend $94,000,000 during 2019. In the reactive Demand Failures capital program, the Company was authorized to spend $87,000,000 during 2019. In the Asset Relocations capital program, the Company was authorized to spend $24,000,000 during 2019. If the Company exceeded these spending amounts for New Business, reactive Demand Failures, and/or Asset Relocations, the Company would be allowed to use deferred accounting treatment for the excess spending. The Company exceeded all three of those thresholds in 2019, as shown in Exhibit A-40 (RTB-13). Company witness Heidi J. Myers proposes the method of recovery for the deferral.

Q. Does the Company propose to continue this deferred accounting treatment?

A. While the Company attempts to project investment needs for the New Business, Demand Failures, and Asset Relocations programs with a high degree of accuracy, the largest factors influencing expenditures in these programs are externally driven. As a result, the Company requests that it be allowed to defer the revenue requirement for any capital spending for these programs above what is included in rates, should the Commission not approve the full requested level of capital spending in this case. Company witness Daniel L. Harry provides a further description of this proposed deferral and needed accounting approvals.

Q. How does the Company ensure that its electric distribution investments are reasonable and prudent?

A. For many projects, the Company considers its proposed electric distribution investment against alternatives and develops concept approval documentation to demonstrate why the selected project is reasonable and prudent. Through this internal concept approval process, the Company ensures that it has a strong business case for selected electric distribution projects. Selected examples of documentation supporting the Company's electric distribution capital projects for the 2021 test year are listed in Exhibit A-41 (RTB-14).

Q. Please explain Exhibit A-41 (RTB-14), column (c).

A. Exhibit A-41 (RTB-14), column (c), indicates the review status of electric distribution concept approvals at the time this filing was prepared. When a concept approval is "approved," it has received all necessary internal approvals and is considered final. Until these necessary approvals are received, a concept approval is "in progress." Exhibit A-41 (RTB-14), column (c), indicates whether respective concept approvals have received all necessary approvals as of the time of this filing. It is important to note that, while concept approvals that are in progress have not yet gone through all final approvals, they still provide a robust engineering basis for projected project costs and for assessing the relative merits of any given project as the Company develops its 2021 workplan.

Q. What capital projects does the Company expect to invest in during the 2021 test year?

A. A comprehensive list of all identified Company projects for the 2021 test year, with projected 2021 test year spending, is provided in Exhibit A-42 (RTB-15). Detailed discussion on each capital program and sub-program is provided in the following sections in my direct testimony. In some sub-programs, the Company has not yet identified projects for the 2021 test year.

Q. Do project cost estimates in the concept approval documents listed in Exhibit A-41 (RTB-14) always align with the project costs listed in Exhibit A-42 (RTB-15) and the project costs discussed throughout this direct testimony?

A. While the project costs in the concept approval documents and the project costs listed in Exhibit A-42 (RTB-15) usually align, there are cases in which they do not. In some cases, concept approvals are written for projects more than two years in advance of the anticipated project execution date. As project execution gets closer, costs may be adjusted due to changing conditions. For multi-year projects, work and corresponding spending may shift among project years, resulting in changing amounts of test year spending even if overall project costs remain consistent.

B. <u>New Business Program</u>

Q. What is the purpose of 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, conductors, transformers, and meters, and in some cases entire new substations. In some cases, costs are offset by customer contributions. Because of the Company's obligation to serve customers in its service territory, the Company generally is required to provide the requested interconnections if the customer meets the requirements set forth in the applicable Company tariffs. The New Business Program consists of the following sub-programs: (i) LVD Lines New Business; (ii) HVD Strategic Customers New Business; (iii) LVD Metering New Business; (iv) LVD Transformers New Business; and (v) Metro New Business.

Q. Are there any "planned" projects in the New Business Program?

A. Although the Company considers New Business spending to be reactive, or "unplanned," as discussed above, due to the customer-requested nature of the program, some New Business projects may be known some time in advance, particularly in the HVD Strategic Customers New Business and Metro New Business sub-programs. However, even these projects with more advanced knowledge must take into account customer schedules, limiting the Company's ability to affect prioritization of New Business work.

Q. What is the Company's total projected investment in the New Business Program in this case, and what is the basis for this level of investment?

A. As previously noted, the settlement in Case No. U-20134 approved $94,000,000 in New Business spending for the 2019 test year, with the stipulation that the Company could use deferred accounting for any New Business spending in 2019 that exceeded that amount. As shown in Exhibit A-30 (RTB-3), line 7, column (c), the Company's 2019 spending was projected to be $131,799,000. The Company expects overall New Business demand to remain level from 2019 to 2020, and for the 2020 bridge year in this filing, the Company projects to spend $131,695,000, as shown in Exhibit A-30 (RTB-3), line 7, column (d). For the 2021 test year, the Company projects to spend $145,162,000, as shown in Exhibit A-30 (RTB-3), line 7, column (f). This spending increase in 2021 is explained in detail in the New Business sub-program sections below.

1. <u>LVD Lines New Business</u>

Q. Please explain what capital projects, activities, and other types of work will be funded by expenditures in the LVD Lines New Business sub-program.

A. The LVD Lines New Business sub-program includes the capital cost of serving new commercial, industrial, residential, and municipal lighting customers. These costs include the necessary overhead and/or underground distribution extensions and enhancements required to complete new service connections, including the cost for new plats and developments. Projects within this sub-program are initiated by customers, whom the Company must serve so long as the requesting party meets the tariff requirements. Customers may be billed for service pursuant to the stipulations of the tariff sheets. In general, the Company does not have advanced knowledge of LVD Lines New Business projects in the preceding year, as the projects are generally completed within the same year that they are requested, and the projections for installed units and investment are based upon historical activity with adjustments for anticipated variations in business.

Q. How does the Company make its projections for units and investments in this sub-program?

A. Projected investment needs for the LVD Lines New Business Program are based primarily on expected new housing starts in the Company's service territory. The Company regularly consults with the Michigan Home Builders Association to review their projections for new housing starts. Based on this forecasting, the Company projects that it will install 9,800 new services in the 2020 bridge year and 10,094 new services in the 2021 test year.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Lines New Business sub-program?

A. The Company is projecting LVD Lines New Business capital expenditures of $94,788,000, as shown in Exhibit A-30 (RTB-3), line 1, column (f).

Q. What has been the historical actual spending in the LVD Lines New Business sub-program for the past five calendar years?

A. The Company's historical actual spending in the LVD Lines New Business sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 1.

Q. Why has the Company increased investment in this sub-program in recent years?

A. The Company has observed an upward trend in the number of new service requests, with an increase in requests each year during the five-year historical period, with a particular increase beginning in the fourth quarter of 2017. The Company has also seen an increase in (i) the average line extension and service footage required for a new service connection, and (ii) the percentage of new services installed underground. Both of these factors account for increased spending over time in this sub-program.

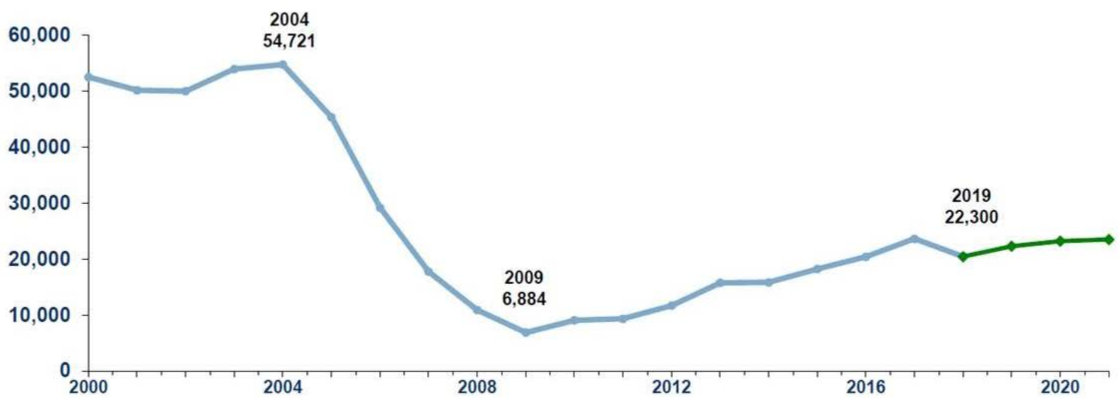
Q. What is the basis for the Company's requested spending level in this filing?

A. The Company's projected spending level for both the 2020 bridge year and the 2021 test year is based on expected service installations. The Company's projected LVD Lines New Business spending for the 2020 bridge year is based on 9,800 new service installations, and the 2021 test year is based on 10,094 new service installations. The Company's New Business investment is tied to Michigan's overall economic health, with a particular connection to new housing starts. Since recovering from the economic downturn in 2012, service installation volumes have increased each year. Data from the Michigan Home Builders Association supports the projection that new housing starts, and therefore new service requests, will continue at recent higher levels, with requests in 2021 in line with or slightly higher than those in 2019 and 2020 and well above the levels seen in the early and middle parts of the last decade.

Q. Please explain the projections of the Michigan Home Builders Association.

A. In 2019, the Michigan Home Builders Association shared information with the Company that it received from the Michigan Department of Treasury. This data projected that, after a modest decrease in 2019, housing starts in Michigan would see moderate growth from 2020 forward. The Company's experience has shown that, due to construction timing, there is usually a delay between the beginning of a housing start and when the Company receives a request for a new service. Correspondingly, the Company is projecting essentially flat growth in LVD Lines New Business spending in 2020 compared to 2019, with modest growth in 2021. The Michigan Home Builders Association data is shown in Figure 21 below.

FIGURE 21
MICHIGAN HOUSING STARTS



Sources: U.S. Bureau of the Census, Michigan Department of Treasury forecast May 2019

Q. What are the historical unit costs for the LVD Lines New Business sub-program?

A. Historical unit costs are provided in Figure 22 below:

FIGURE 22
LVD LINES NEW BUSINESS UNIT COSTS

	2014	**2015**	**2016**	**2017**	**2018**
New Services	7,512	8,004	8,818	9,353	9,864
Cost /Service	$5,300/service	$5,700/service	$4,900/service	$7,000/service	$8,900/service

Q. Please explain the variation in unit costs over time.

A. As discussed above, there has been a significant increase in unit costs since 2016 due to a large increase in line extension footage to accommodate new services, along with an increase in the footage of services themselves. To illustrate this, in 2014 the Company installed 2,032,000 feet of line extensions and 740,000 feet of services in response to new service requests. By 2018, this had increased to 2,634,000 feet of line extensions and 1,029,000 feet of services. This raw increase in footage has raised both unit costs and total program costs. Furthermore, the Company is investing, at customer request, in new underground infrastructure to support new service connections. In 2014, 67% of the Company's line extension footage to accommodate new services was overhead, with 33% underground. By 2018, that had shifted to 52% overhead and 48% underground, further increasing unit costs and total program costs. Additionally, in Case No. U-18039, the Commission issued a June 9, 2016 Order that allows the Company to waive certain contribution in aid of construction ("CIAC") requirements, including those related to the difference in costs between providing underground and overhead service, for customers if the revenues from the new load will offset the Company's costs in providing the new service.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Lines New Business sub-program?

A. Fundamentally, new customers benefit when they are connected to the Company's distribution system through the LVD Lines New Business sub-program because customers' homes, businesses, and other facilities receive access to the grid and the electricity that it provides. Economic growth in Michigan depends on the ability of new residential, commercial, and industrial facilities to access utilities, including electricity. The Company is committed to providing a new service installation to every customer who requests it, and the requested spending level will allow the Company to do that.

Q. Are there any prioritized projects that make up the requested spending level in the LVD Lines New Business sub-program?

A. As a general matter, due to the large volume of projects and the demand driven nature of the sub-program, the Company does not plan for these projects on an individual level. However, the Company is planning infrastructure spending to support the PowerMIDrive and PowerMIFleet electric vehicle pilot programs, as supported by Company witness Sarah L. Nielson, as part of the LVD Lines New Business sub-program. This spending is for infrastructure upgrades related to the installation of electric vehicle chargers as part of these programs. In the 2021 test year, the Company is projecting to spend $550,000 in the LVD Lines New Business sub-program on the PowerMIDrive Program and $500,000 in the LVD Lines New Business sub-program on the PowerMIFleet Program.

2. <u>HVD Strategic Customers New Business</u>

Q. Please explain what capital projects, activities, and other types of work will be funded by expenditures in the HVD Strategic Customers New Business sub-program.

A. The HVD Strategic Customers New Business sub-program consists of the capital costs to meet the needs of large Commercial and Industrial customer new business requirements that are too energy-intensive to be served by the area LVD system, addressing both existing customers and proposed new customers looking to locate a new site in Michigan. Typical investments for this program include dedicated substations and interconnections of dedicated substations to the HVD system with poles, conductors, and metering to connect new industrial customers.

Q. How does the Company plan projects and develop investment projections in this sub-program?

A. Projected test year spending amounts are based on currently known and planned work, as well as expected expenditures that will be required for related new business work based on historical spending levels. These costs are net of any contributions made to Consumers Energy by customers in support of their project. Customer service inquiries in this sub-program are continuous and are driven by customer business needs. Unlike many of the Company's other capital programs, this sub-program and its timing of projects and investments are driven to meet the needs and expectations of these specific customers. The timeline from a completed customer agreement to a final connection can vary from six months to two years. Consequently, some projects are known well enough in advance to be specifically captured in a rate case filing, while others are not. To account for those that are not yet known, the Company considers both currently known projects and historical spending levels to project test year investment needs.

Q. Typically, how often, and how far in advance, does the Company know, or have a good indication, that there will be a customer need before a customer agreement is completed?

A. The Company typically receives a customer service inquiry prior to a completed customer agreement. These inquiries give the Company an indication of potential customer needs, but there is no commitment from the customer to move forward with a project until a customer agreement is completed. Therefore, while the Company does have some advanced indication of potential customer needs prior to a completed customer agreement, the Company will not have certainty that the project will move forward until a customer agreement is completed. The time between when a customer service inquiry is received and when a customer agreement is completed can vary greatly ranging from two or three months to several years or more and is largely reliant on the customer's schedule and customer's decision to move forward.

Q. What is the Company's projected 2021 test year spending level, 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 $17,281,000 in the 2021 test year, as shown in Exhibit A-30 (RTB-3), line 3, column (f).

Q. What has been the historical actual spending in the HVD Strategic Customers New Business sub-program for the past five calendar years?

A. The Company's historical actual spending in this sub-program for the past five calendar years are shown in Exhibit A-29 (RTB-2), line 3.

Q. Why does historical spending in this sub-program show significant year-to-year variation?

A. Spending in this sub-program can be inherently variable from year to year, because the projects and investments undertaken are relatively few and are specifically tailored to the needs of the customer requesting the work. This was particularly illustrated in 2016 when the Company completed a large project in this sub-program for a large customer in mid-Michigan, which accounted for the unusually high costs that year. Conversely, the sub-program incurred a negative amount of spending in 2018, when the sub-program received money that had been held for a refundable deposit from an earlier project; this deposit was credited back to the sub-program, resulting in negative spending, from an accounting point of view, during that year.

Q. How is the Company treating spending outliers, such as from 2016, in projecting its HVD Strategic Customers New Business spending for the 2021 test year?

A. These spending outliers reinforce the inherent variability of this sub-program, particularly the high spending in 2016; the $27,864,000 spent by the Company in that year did in fact represent actual HVD New Business projects that had to be completed, which further illustrates the prudence of allowing for some spending to be set aside for projects that have not yet been identified.

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. Spending for the 2020 bridge year and 2021 test year is based on known and planned projects, with some allowance for additional projects to be identified based on later customer requests. In the 2021 test year, the Company is projecting to spend $17,281,000 in this sub-program, based on known and planned projects, with an allowance of $1,891,000 for additional projects to be identified closer to and potentially during the test year based on customer requests. In 2021, the Company has already identified several projects, as described below.

Q. Are there any prioritized projects that make up the requested spending level in the HVD Strategic Customers New Business sub-program?

A. The Company has identified six projects, covering two locations, for the 2021 test year, which are shown in Exhibit A-42 (RTB-15), page 1, lines 1 through 6. Please note that specific customer information is confidential and cannot be publicly provided by the Company. The six projects are as follows:

- A new 138 kV dedicated customer substation in southwest Michigan;
- Two new 1.3-mile 138 kV lines to connect the new dedicated customer substation in southwest Michigan;
- Relocation of the Cooper 46 kV line to accommodate the new dedicated customer substation in southwest Michigan;
- Relocation of the Ampersee 46 kV line to accommodate the new dedicated customer substation in southwest Michigan; and
- New 138 kV dedicated customer substation in northwest Michigan.

Q. What is the supporting justification for building these projects at these sites?

A. The Company developed these projects to build new dedicated substations for these locations, with corresponding line relocations as necessary, after a thorough analysis of alternatives. The Company developed detailed concept approvals for these projects, as shown in Exhibit A-41 (RTB-14), lines 1 and 2.

Q. Are there costs included in the Company's request for which specific projects have not yet been identified?

A. Yes.

Q. What is that amount?

A. $1,891,000.

Q. For any requested spending that is not tied to a listed project, please explain how the Company will identify additional projects to account for that spending.

A. The Company will identify additional projects as they are requested by customers. Customers typically contact the Company's Business Customer Care team, who refers the customer to the HVD planning engineer for the corresponding geographic location. The customer will identify their location, proposed new maximum demand, a proposed schedule for new load to come online, and other information. The HVD planning engineer performs studies and develops conceptual cost estimates for any required new or upgraded Company facilities to serve the new load, including any CIAC costs applicable to the customer. If agreed to by the customer, a schedule for the work is developed. It is likely, based on experience, that customers could request projects for the 2021 test year late in 2020 or even early in 2021.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the HVD Strategic Customers New Business sub-program?

A. The projected expenditures in the HVD Strategic Customers New Business Program are needed to respond to customer requests in order to allow those customers to further develop their businesses, and thereby benefit the broader economy of the state of Michigan. Increased new large customer connection and load additions provide the benefits of job development and other state and local revenue streams associated with business expansion. Additionally, all Company customers benefit from these large customer additions – by increasing total load, utility costs are spread across a larger customer base.

3. LVD Metering New Business

Q. Please explain what capital projects, activities, and other types of work will be funded by expenditures in the LVD Metering New Business sub-program.

A. The LVD Metering New Business sub-program supplies meters as needed for new business connections. The LVD Metering New Business sub-program is one component of a single purchase plan, which also includes the LVD Metering Demand Failures sub-program. The

Company purchases meters, metering transformers, and meter sockets as part of this purchase plan, with a percentage of the expenditures allocated to the LVD Metering New Business sub-program. The purpose of such purchases is to maintain metering accuracy and to support the demand for metering equipment created by emergent work, including new business and equipment failures. From this single purchase plan, expenditures are allocated between LVD Metering New Business and LVD Metering Demand Failures based on the historical percentage of actual work that was done in each sub-program. The percentage split is reviewed annually based on prior-year actual work, and the percentages are revised if necessary.

Q. What are the allocation percentages for the 2021 test year?

A. For the 2021 test year, 51% of metering purchases in this purchase plan are allocated to LVD Metering New Business and 49% of purchases are allocated to LVD Metering Demand Failures. I discuss that sub-program later in my direct testimony.

Q. How does the Company project the total purchase level necessary for this single purchase plan?

A. This purchase plan is developed based on projected activity in the New Business and Demand Failures programs, which are in turn based largely on historical data. In addition to historical data, the Company also considers estimates of new business connections in future years, anticipated levels at which meters in the field must be replaced, and whether replaced meters are retired or refurbished and recycled back into service.

Q. How does this sub-program maintain metering accuracy?

A. The sub-program maintains metering accuracy by replacing meters in service that are non-functional, damaged, or whose accuracy has been questioned by the customer. Those meters are exchanged with recently purchased or calibrated meters that the Company knows to be within Commission accuracy requirements, ensuring accurate registration and billing.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Metering New Business sub-program?

A. The Company is projecting LVD Metering New Business capital expenditures of $10,868,000 in the 2021 test year, as shown in Exhibit A-30 (RTB-3), line 4, column (f).

Q. What has been the historical actual spending in the LVD Metering New Business sub-program for the past five calendar years?

A. The Company's historical actual spending in the LVD Metering New Business sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 4.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Total expenditures in both this sub-program and in the LVD Metering Demand Failures sub-program have varied from year to year based on the number of meters the Company has had to purchase. Expenditures in both sub-programs also vary from year to year as allocation percentages shift based on the historical actual work of the prior year. From 2012 through 2017, the Company completed a program to deploy smart meters to all customers; during that period, the initial purchase of new smart meters was funded by that special program. Spending in the LVD Metering New Business and Demand Failures sub-programs was limited to a relatively low number of legacy meter purchases and a small amount of smart meter purchases to replace smart meters for customers that already had them; that is, if a customer received a smart meter, and that smart meter subsequently failed, then the *replacement* smart meter would be funded by this sub-program. Therefore, in

2014 spending in this sub-program remained fairly low and increased from there as the Company moved through the initial deployment of smart meters. In 2017, the Company experienced an increase in the volume of legacy meters that had to be returned to the manufacturer or repaired, which resulted in a notable increase in spending on the Company's metering purchase plan in that year. After deployment of smart meters ended in 2017, spending on the Company's metering purchase plan returned to a business-as-usual mode, with all metering purchases again allocated to the LVD Metering New Business and LVD Metering Demand Failures sub-programs.

Q. What is the basis for the Company's requested spending level for this sub-program in this filing?

A. As stated above, the Company's spending in this sub-program was depressed through 2017 as many smart meter purchases were funded through the Company's smart meter deployment program, which has ended. Additionally, the Company's new meter purchases going forward are largely smart meters, which cost more than legacy meters – the basic cost of a legacy meter was $20, while the basic cost of a smart meter is $125. The Company does expect that more smart meters, when replaced, will be able to be refurbished and recycled going forward, so projected spending for the 2020 bridge year and 2021 test year is lower than the higher level seen in 2019. Furthermore, the Company is projecting increases in other areas of New Business investment, and since the LVD Metering New Business sub-program in part supports other New Business investment and the allocation percentage is based on New Business activity, the spending level for the LVD Metering New Business sub-program in this filing is higher than the historical average as the number of required new meter installations and the allocation percentage increase.

Q. What are the historical unit costs for the LVD Metering New Business sub-program?

A. Since distribution meters are purchased as part of a single purchase plan, unit costs apply across the LVD Metering New Business and LVD Metering Demand Failures sub-programs. Historical unit costs for all LVD Metering sub-programs are provided in Figure 23 below:

FIGURE 23
LVD METERING UNIT COSTS

	2014	***2015***	***2016***	***2017***	***2018***
Smart meters	3,000	7,960	23,310	32,824	37,728
Legacy meters	1,440	1,440	534	1,309	1,678
Total meters	4,440	9,400	23,844	34,133	39,406
$/meter	$1,300	$1,160	$530	$580	$530

Q. Please explain any variation in unit costs over time.

A. Since 2016, unit costs have been relatively consistent for this sub-program and have been trending downward over the five historical years. In 2014 and 2015, the Company was purchasing fewer meters through the single purchase plan represented by the LVD Metering New Business and Demand Failures sub-programs, due to the smart meter deployment program. However, the Company was still purchasing metering transformers and meter sockets through the regular program. Consequently, total metering costs are divided over fewer meters in 2014 and 2015, in the table above, even though those total metering costs include all metering transformers and meter sockets. This affects the unit costs shown for 2014 and 2015.

Q. Why is the Company continuing to purchase any legacy meters after the end of mass deployment of smart meters?

A. The legacy meters in the Company's purchase plan support operation of MV90 meters. MV90 meters essentially provide a type of automated meter reading on some large commercial and industrial customers, by which meter interval data is collected either by a telephone connection or is manually read by a field worker. MV90 meters were determined to be out of scope for initial smart meter deployment for two main reasons. First, the billing tariffs for these customers are complex and would have required extensive hours of programming; since MV90 was already functional, the Company kept these meters out of scope for initial smart meter deployment. Second, some of these MV90 meters have a pulse output to provide real time data to customers and at the time of smart meter deployment, the meter vendor did not offer a smart meter option with pulse output, so the use of MV90 legacy meters was still required. Starting in 2019, the vendor began offering a smart meter with pulse output, which will allow the Company to convert some of these MV90 legacy meters to smart meters.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Metering New Business sub-program?

A. Metering is an essential part of the Company's broader requirement to connect new customers through its overall New Business Program, the benefits of which were described earlier in my direct testimony.

4. LVD Transformers New Business

Q. Please explain what capital projects, activities, and other types of work will be funded by expenditures in the LVD Transformers New Business sub-program.

A. The LVD Transformers New Business sub-program supplies the distribution transformers that are part of many new business connections, providing the means to supply electricity to the customer at an acceptable voltage, with the number of transformers needed driven primarily by activity in the LVD Lines New Business sub-program. The LVD Transformers New Business sub-program is one component of a single purchase plan for distribution transformers, which also encompasses the LVD Transformers Demand Failures and LVD Transformers Capacity sub-programs. From this single purchase plan, expenditures are allocated among the three sub-programs based on the historical percentage of actual work that was done in each sub-program. For the 2021 test year, the projected spending for each of these three sub-programs are based on historical percentages of actual work that are current as of the time of this filing. The percentage split is reviewed annually based on prior-year actual work, and the percentages are revised if necessary, so these allocation percentages can shift from year to year based on relative activity levels in the New Business, Demand Failures, and Capacity program areas.

Q. What are the allocation percentages for the 2021 test year?

A. For the 2021 test year, 53% of distribution transformer purchases in this purchase plan are allocated to LVD Transformers New Business, 40% of purchases are allocated to LVD Transformers Demand Failures, and 7% of purchases are allocated to LVD Transformers Capacity.

Q. How does the Company project the total purchase level necessary for this single purchase plan?

A. The Company develops its plan by estimating the total number of transformers needed across the three sub-programs, based on historical actual data, with potential fluctuation in individual years based on lines projects in the Company's reactive spending programs, particularly New Business and Demand Failures. The Company estimates a 2% annual average increase in total expenditures on new transformers each year.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Transformers New Business sub-program?

A. The Company is projecting LVD Transformers New Business capital expenditures of $18,724,000 in the 2021 test year, as shown in Exhibit A-30 (RTB-3), line 5, column (f).

Q. What has been the historical actual spending in the LVD Transformers New Business sub-program for the past five calendar years?

A. The Company's historical actual spending in the LVD Transformers New Business sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 5.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Total expenditures in this sub-program have varied from year to year based on the need for distribution transformers. Expenditures in this sub-program also vary from year to year as allocation percentages shift based on the historical actual work of the prior year. In 2018 and 2019, the Company experienced a significant increase in LVD Lines New Business work, as I discussed earlier in my direct testimony. This affected allocation percentages for 2019, as reflected by the large increase in LVD Transformers New Business spending in 2019.

Q. What is the basis for the Company's requested spending level in this sub-program?

A. The Company is projecting increases in other areas of New Business investment, and since the LVD Transformers New Business sub-program, in part, supports other New Business investment, the spending level for the LVD Transformers New Business sub-program in this filing is higher than historical amounts.

Q. What are the historical unit costs for the LVD Transformers New Business sub-program?

A. Since transformers are purchased as part of a single purchase plan, unit costs apply across the LVD Transformers New Business, LVD Transformers Demand Failures, and LVD Transformers Capacity sub-programs. Historical unit costs for all LVD Transformers sub-programs are provided in Figure 24 below:

FIGURE 24
LVD TRANSFORMERS UNIT COSTS

	2014	***2015***	***2016***	***2017***	***2018***
Transformers	11,830	10,775	10,598	13,744	8,732
$/Transformer	$2,600	$2,800	$2,500	$2,800	$3,350

Q. Please explain any variation in unit costs over time.

A. Unit costs for transformers have increased marginally over the historical period, partially due to inflation. Additionally, the Company maintains an inventory of over 400 transformer types, and unit costs in a given year can vary depending on the mix of transformer types that the Company purchases in a given year.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Transformers New Business sub-program?

A. The installation of distribution transformers is an essential part of the Company's broader requirement to connect new customers through its overall New Business program, the benefits of which were described earlier in my direct testimony.

5. Metro New Business

Q. Please explain what capital projects, activities, and other types of work will be funded 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 six 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 (C6.2 Underground Policy, Part F). These customers commonly fall into two categories: (i) new construction; and (ii) extensive remodeling of an existing building or conversion of a building from office or commercial use to mixed use or residential. New construction involves a new building on either a vacant site or following a complete tear down of an existing structure. For an extensive remodel of an existing building, the existing structure of building is intact, but electrical systems and service from utility are undersized, due to new building usage or code requirements (e.g., fire pump, HVAC, etc.). Additionally, converting a building to mixed use or residential use may affect the necessary voltages for customers in the building. Occasionally, a customer with a significantly different load profile intends to occupy an existing space, requiring upgrades to the system.

Q. How does the Company make its projections for needed investments in this sub-program?

A. In some cases, customers contact the Company well in advance, allowing for Metro New Business project costs to be determined and planned for in longer-range spending forecasts. It should be noted that even with advance notice, customers' respective developments may take years to come to fruition, as customers seek funding and deal with other issues relative to economic development in urban core areas. Therefore, even advance Metro New Business notice projects can have fluid timelines. In other cases, customers contact the Company later in their development process, with desired service in the near future, meaning those Metro New Business project costs cannot be accounted for in longer-term forecasting. Therefore, the Company also uses analysis of historical trends and data to forecast the level of investment needed in this sub-program.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the Metro New Business sub-program?

A. The Company is projecting Metro New Business capital expenditures of $3,500,000 in the 2021 test year, as shown in Exhibit A-30 (RTB-3), line 6, column (f).

Q. What has been the historical actual spending in the Metro New Business sub-program for the past five calendar years?

A. The Company's historical actual spending in the Metro New Business sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 6.

Q. If spending in any of the five historical years is a significant outlier, please explain why this happened.

A. The Company's investment in Metro New Business increased significantly in 2019, as there was significant economic development and urban renewal, with corresponding construction work, in several of the downtown areas served by the Company's Metro systems. For example, the Studio Park development in Grand Rapids involved a $1,289,000 Metro New Business project for the Company.

Q. What is the basis of the Company's requested spending level for Metro New Business in this filing?

A. The Company's projected bridge year and test year spending level in Metro New Business is in line with historical averages. In this particular sub-program, the Company does not believe that the unusually high spending level seen in 2019 will remain so high permanently; the relatively limited geographic area of the Metro systems limits the number of New Business projects that can take place for a sustained period over multiple years.

Q. Are there any prioritized projects that make up the requested spending level in the Metro New Business sub-program?

A. In the 2021 test year, the Company has already identified one project in Flint, costing $120,000, and three projects in Grand Rapids, costing a total of $850,000. These projects are listed in Exhibit A-42 (RTB-15), page 1, lines 9 through 12.

Q. Are there projects that are not currently included in this list but that could be reprioritized to take place during the 2021 test year if circumstances change?

A. As previously stated, while Metro New Business projects can be identified in advance on some occasions, project timelines can be fluid because customers' own development timelines often change in response to other factors. The projects listed above are those that the Company expects to perform in 2021. However, it is possible that one or more customers could request a project for 2022 or later, and then subsequently request that the Company perform the work in 2021 if the customer had a change in timeline.

Q. Are there costs included in the Company's request for which specific projects have not yet been identified?

A. Yes.

Q. What is that amount?

A. $2,530,000.

Q. For any requested spending that is not tied to a listed project, please explain how the Company will identify additional projects to account for that spending.

A. The Company will identify additional projects as they are requested by customers, as is common throughout the New Business Program. New requests are evaluated by the Metro Planning group based on several impacts that impact design, including:

- Customer voltage required;
- Customer anticipated load;
- Potential future load from customer;
- Potential development of surrounding area;
- Existing system capacity; and
- Existing system condition in area.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the Metro New Business sub-program?

A. Metro New Business projects are important not only for the customers impacted, but well-planned projects and new infrastructure may decrease future outage time for neighboring customers when expansion of buildings occurs or surrounding areas are developed. Additionally, increased new customer connections and load additions provide benefits to local communities and to Michigan through development of jobs and other revenue streams associated with business expansions.

C. Demand Failures Program

Q. What is the purpose of the Demand Failures Program?

A. The purpose of the Demand Failures Program is to address issues related to customer interruptions and failures of equipment on the distribution system. When equipment fails, and customers are interrupted, the Company is obligated to fix the issue and restore customers as quickly as possible. If the Company replaces failed equipment in this process, the capital expenditures take place in the Demand Failures Program. Because of this, the work in all of the Demand Failures sub-programs is emergent; it is planned, prioritized, and completed as issues arise, with specific projects not planned far in advance. Therefore, sub-programs in Demand Failures by their nature do not include lists of anticipated projects, and projects cannot be meaningfully reprioritized on a year-to-year basis. Projected spending is generally based on historical spending and potentially adjusted for observed trends, as I will discuss below when explaining each sub-program. The sub-programs in the Demand Failures Program are: (i) LVD Lines Demand Failures; (ii) HVD Lines and Substations Demand Failures; (iii) LVD Substations Demand Failures;

(iv) LVD Metering Demand Failures; (v) LVD Transformers Demand Failures; (vi) Streetlighting Center Suspension Replacements; and (vii) Metro Failures.

Q. Has the Demand Failures Program historically included other costs or types of work?

A. Yes. Through 2018, the Demand Failures Program also proactively replaced assets that were judged to be at risk of imminent failure by a Company or contractor inspection. Such work was included in the Company's Demand Failures plan in Case No. U-20134, and in other prior rate cases.

Q. How has that changed?

A. In reaching a settlement in Case No. U-20134, the parties agreed to allow the Company to spend $87,000,000 on Demand Failures in 2019, but only on "reactive" Demand Failures, which were defined to be situations in which an asset actually physically or electrically failed in some way that put the system outside of normal operating conditions, causing customer outage(s) and/or a public safety issue, creating an immediate need to repair or replace the asset. Work to repair or replace assets judged to be at risk of imminent failure, but which had not actually failed, were excluded from that settlement amount. Correspondingly, in 2019 the Company moved all work formerly in the "imminent" Demand Failures Program into new sub-programs referred to as Rehabilitation. All of the work discussed in the Demand Failures sub-programs below consist of "reactive" work. Those Rehabilitation sub-programs are discussed later in my direct testimony as part of the Reliability Program.

Q. How did the Company differentiate between "reactive" and "imminent" Demand Failures?

A. In order to comply with the settlement in Case No. U-20134, the Company reviewed its Demand Failures projects in recent years and determined which were in response to actual failures on the system and which were in response to imminent failures. Going forward, the Company has classified different investment categories as reactive, imminent, or a combination of the two, and assigned those categories to a Demand Failures sub-program or a Rehabilitation sub-program under the Reliability Program. I will discuss this in greater detail in covering each sub-program. In every case, Demand Failures projects are responding to actual failures, defined as a situation where an asset has physically or electrically failed in some way that has put the system outside of normal operating conditions, causing customer outage(s) and/or a public safety condition, creating a need to repair or replace an asset.

Q. What is the Company's total projected investment in the Demand Failures Program in this case, and what is the basis for this level of investment?

A. As previously noted, the settlement in Case No. U-20134 approved $87,000,000 in reactive Demand Failures spending for the 2019 test year, with the stipulation that the Company could use deferred accounting for any New Business spending in 2019 that exceeded that amount. As shown in Exhibit A-33 (RTB-6), line 8, column (c), the Company's 2019 spending was projected to be $158,586,000. Spending in the Demand Failures Program decreases from 2019 to 2020 due to the shift of imminent Demand Failures spending to the Reliability Program, and for the 2020 bridge year in this filing, the Company projects to spend $111,154,000, as shown in Exhibit A-33 (RTB-6), line 8, column (d). For the 2021 test year, the Company projects to spend $122,568,000, as shown in Exhibit A-33 (RTB-6), line 8, column (f). This spending increase in 2021 is explained in detail in the Demand Failures sub-program sections below.

1. <u>LVD Lines Demand Failures</u>

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the LVD Lines Demand Failures sub-program.

A. The LVD Lines Demand Failures sub-program includes capital expenditures incurred during customer interruption restoration, or during the repair or replacement of LVD equipment due to unanticipated failure. This includes immediate response to day-to-day equipment failures and capitalization of projects during storm restoration. Projects are not planned far in advance in this sub-program, because the sub-program is meant to quickly respond to equipment failures and customer interruptions that have already taken place. The LVD Lines Demand Failures sub-program consists of two investment categories: (i) service restoration orders; and (ii) street light failures. The sub-program historically included investment categories for emergent rehabilitation projects; and for security assessment repairs. Both of these investment categories are now funded in the LVD Lines Rehabilitation sub-program under the Reliability Program. The LVD Lines Demand Failures sub-program also historically included an investment category for zonal projects for rehabilitation, voltage improvement, and system protection. That work is now included in the targeted circuit improvement investment category in the LVD Lines Reliability sub-program.

Q. Please describe the service restoration orders investment category.

A. Once a failure or other damage to the system has occurred, the Company prioritizes its response by categorizing damage by severity, as either a Priority 1 (“P1”) or Priority 2 (“P2”), as shown in Figure 25 below:

FIGURE 25
LVD HAZARD CODES

Code	Description
P1 - Public Safety	
P1A	Safety Code Violation
P1B	Unusual Public Hazard
P2 - Failures	
P2A	Floating Phase / Neutral
P2B	Broken / Severely Cracked Crossarm
P2C	Damaged / Cracked Cutout
P2D	Damaged / Cracked Insulators
P2E	Pole: Needing Immediate Replacement
P2F	Faulted Underground Radial Cable or Service
P2G	Overhead or Underground Equipment out of Service
P2H	Streetlights out of Service

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 actually 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 14 calendar days. However, this time can extend beyond 14 days, such as when the failed equipment has been bypassed and new equipment is on order for replacement.

Q. When the Company determines that service restoration activity is required, what types of projects are considered?

A. The Company performs the following types of service restoration capital work:

- **Failed Underground Cable –** When a failure occurs on an underground cable, the Company identifies and fixes the fault immediately to restore service to customers. If the underground cable is looped (has feeds from multiple directions), the fault is isolated and service to customers is restored;
- **Failed Distribution Transformer –** These failures are addressed immediately and could warrant further evaluation to determine if the transformer was adequately sized for the load, which in some cases leads to replacement of the existing transformer with a larger one;
- **Car-Pole Accident –** When car-pole accidents result in damage to poles, the Company immediately assigns an available crew to ensure safety of the area, replace the pole, and restring or splice the conductor;
- **Broken Crossarm, Pin/Insulator, or Pole** – When poles and other components fail, electric service may be interrupted, or public safety might be affected where the wire is left hanging below the required clearance or out of normal operating position. The Company will replace any broken equipment (i.e., a cracked crossarm); 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 trends has the Company recently observed regarding service restoration orders?

A. Service restoration orders have been increasing in recent years. The Company believes that this upward trend is indicative of increasing levels of adverse weather and asset deterioration on the LVD system, as discussed earlier in my direct testimony, which contributes to asset failures and the need for restoration and rehabilitation work. This upward trend is likely to continue in the near-term future as assets are replaced at levels insufficient to keep up with deterioration. The Company's service restoration orders in 2014 through 2019 are shown in Figure 26 below.

FIGURE 26
SERVICE RESTORATION ACTIVITIES (DEMAND) 5-YEAR HISTORY

	2014	2015	2016	2017	2018	2019
Service Restoration Orders	13,329	9,760	14,842	20,665	20,665	20,292

Q. Please describe the street light failures investment category.

A. Similar to service restoration, the Company replaces failed street light fixtures as they fail. In recent years, an increasing number of streetlight failures can be attributed to a failed underground conductor which requires a full crew to repair. As with service restoration orders, these projects are emergent, not planned in advance.

Q. How does the Company project investment needs in the LVD Lines Demand Failures sub-program?

A. The LVD Demand Failures sub-program responds to immediate demands. Because the work in this sub-program responds to emergent needs, necessary investment in the sub-program fluctuates from year-to-year. The Company develops its forecasted needs based primarily on historical spending on failures, accounting for observed trends.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Lines Demand Failures sub-program?

A. The Company is projecting LVD Lines Demand Failures capital expenditures of $78,538,000, as shown in Exhibit A-33 (RTB-6), line 1, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the two investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 27 below.

FIGURE 27
LVD LINES DEMAND FAILURES INVESTMENT CATEGORY
EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Service restoration orders	$63,045,000	20,145
Street light failures	$15,493,000	19,700
Total	**$78,538,000**	

Q. What has been the historical actual spending in the LVD Lines Demand Failures sub-program for the past five calendar years?

A. The historical actual spending in the LVD Lines Demand Failures sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 35.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Spending in this sub-program varies considerably based on the number of service restoration orders, which in turn vary considerably with weather conditions. The Company experienced a significant wind storm in March 2017 that resulted in an increase in service restoration spending in that year. The Company also experienced significant catastrophic storm activity in 2019, again driving higher spending. Through 2017, spending in this sub-program also included work that is now part of the LVD Lines Reliability and LVD Lines Rehabilitation sub-programs.

Q. What is the basis for the Company's projected spending level in this sub-program?

A. The Company developed its forecasted needs for the 2020 bridge year and 2021 test year based primarily on historical spending on failures, accounting for observed trends. As discussed, the Company's electric distribution system is experiencing increased weather challenges and deterioration, meaning service restoration orders will likely increase, resulting in higher spending. The Company is also increasing its spending on street light failures as it accelerates replacement of older, obsolete lights with light emitting diode ("LED") lights; instead of repairing failed obsolete lights, the Company is now replacing them with new LED units.

Q. What are the historical unit costs for each of the LVD Lines Demand Failures investment categories?

A. Historical unit costs for each category are provided in Figure 28 below:

FIGURE 28

LVD LINES DEMAND FAILURES INVESTMENT CATEGORY UNIT COSTS

Investment Categories	*2014*	*2015*	*2016*	*2017*	*2018*
Service restoration orders	$920/order	$1,600/order	$1,500/order	$1,400/order	$1,600/order
Street light failures	$370/order	$760/order	$610/order	$510/order	$470/order

Q. Please explain any variation in unit costs over time.

A. Service restoration costs can vary modestly due to variations in size and complexity of work orders.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Lines 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. Service restoration investment also provides a future reliability benefit to customers, by improving the condition of system equipment when failed components are replaced.

2. <u>HVD Lines and Substations Demand Failures</u>

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the HVD Lines and Substations Demand Failures sub-program.

A. The HVD Lines and Substations Demand Failures sub-program supports the capital replacement of failed 46 kV and 138 kV lines and substation equipment to restore customer service and maintain reliability. This sub-program replaces assets that have actually failed in the field, including HVD substation equipment, HVD poles and switches, and HVD cross-arms and insulators. This sub-program historically included the repair or replacement of these same classes of assets that the Company evaluated to be in a state of imminent failure, but those projects have been reclassified to the HVD Lines and Substations Rehabilitation sub-program discussed later in my direct testimony. The HVD Lines and Substations Demand Failures sub-program consists of five investment categories: (i) pole replacements; (ii) pole top assembly replacements; (iii) switch (including MOAB) replacements; (iv) miscellaneous other replacements; and (v) HVD substation failure projects. The first four investment categories support projects on HVD lines.

Q. Please provide a general description of the four HVD lines failure investment categories.

A. Pole replacements consist of replacing pole structure(s), including associated pole top hardware. Pole top assembly replacements consist of replacing cross-arms, cross-arm braces, and insulators. Switch replacements, including MOABS, are the replacement with an optimally-sized switch meeting current standards. Miscellaneous other replacements may include other capital items such as a span of conductor or lightning arrestor.

Q. What are MOABS?

A. MOABS are on/off switches used to automatically sectionalize faulted HVD line sections, to allow the un-faulted sections to be automatically re-energized and able to service customers in the un-faulted section and are a key component of SCADA on the HVD system. When MOABS are installed on an HVD line, they contain a controller that monitors voltage on the line and that communicates with adjacent MOABS through a fiberoptic line. MOABS will sectionalize a line if they detect a loss of voltage, but they do not interrupt the flow of current. These controllers contain cellular modems to enable remote monitoring and operation. The Company is currently in a process of replacing existing MOABS to bring them to current SCADA design standards.

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, which is included but not limited to power transformers, breakers, capacitors, switches, bushings, station batteries/chargers, regulators, voltage transformers, and facilities (such as fences, gates, and driveways).

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the HVD Lines and Substations Demand Failures sub-program?

A. The Company is projecting HVD Lines and Substations Demand Failures capital expenditures of $4,180,000, as shown in Exhibit A-33 (RTB-6), line 2, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the five investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 29 below.

FIGURE 29
HVD LINES AND SUBSTATIONS DEMAND FAILURES INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Pole replacements	$1,200,000	58
Pole top assembly replacements	$540,000	87
Switch (inc. MOAB) replacements	$180,000	3
Miscellaneous other replacements	$160,000	6
HVD substation failure projects	$2,100,000	n/a
Total	**$4,180,000**	

Individual HVD substation failure projects can range widely in scope and cost, from small transformer replacements costing $12,000 up to large transformer replacements costing $2,000,000. This variation in that investment category makes it impractical to project a unit total. The projected spending of $2,100,000 on HVD substation failure projects is based on historical actual spending without respect to units.

Q. What has been the historical actual spending in the HVD Lines and Substations Demand Failures sub-program for the past five calendar years?

A. The historical actual spending in the HVD Lines and Substations Demand Failures sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 36.

Q. If spending in any of the five historical years is a significant outlier, please explain why this happened.

A. In late 2017 and early 2018, the Company experienced several large transformer failures, particularly at the Pasadena and Edenville substations, which resulted in increased spending in this sub-program during 2018.

Q. What is the basis for the Company's requested spending level in this sub-program?

A. Historical spending in this sub-program includes spending to repair or replace assets evaluated by the Company to be in a state of imminent failure. That spending has been reclassified to the HVD Lines and Substations Rehabilitation sub-program. The spending included in the HVD Lines and Substations Demand Failures sub-program in this filing is limited to the Company's projected spending needs to address actual component failures, and the projected spending for the 2020 bridge year and 2021 test year is in line with the historical actual failures experienced by the Company.

Q. What are the historical unit costs for each of the HVD Lines and Substations Demand Failures investment categories?

A. Historical unit costs for each category are provided in Figure 30 below:

FIGURE 30

HVD LINES AND SUBSTATIONS DEMAND FAILURES INVESTMENT CATEGORY UNIT COSTS

Investment Categories	*2014*	*2015*	*2016*	*2017*	*2018*
Pole replacements	$15,400/ project	$13,400 /project	$16,700 /project	$18,100 /project	$19,500 /project
Pole top assembly replacements	None	$5,300/project	$5,700/project	$5,700/project	$6,200/project
Switch replacements	$49,300 /project	$31,200 /project	$69,100 /project	$60,500 /project	$77,300 /project
Miscellaneous other replacements	$58,500 /project	$15,500 /project	$27,400 /project	$15,000 /project	$37,100 /project

As discussed above, the scope and cost of HVD substation failure projects vary dramatically, and the Company does not track unit costs *per se* in that investment category.

Q. Please explain any variation in unit costs over time.

A. Specific individual projects can vary widely in cost from project to project based on specific project conditions, and as a result unit costs can also vary. In particular, since the miscellaneous other replacements investment category encompasses a wide variety of projects, the unit costs in that category show wide variation. For example, in 2018 the Company experienced underground cable failures on the Janes and Wealthy-Ellis lines, which cost approximately $157,000 and $270,000 to repair, respectively. This skewed the average cost in the miscellaneous other replacements investment category upward in 2018.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the HVD Lines and Substations Demand Failures sub-program?

A. The projected test year amount provides 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.

3. <u>LVD Substations Demand Failures</u>

Q. Please explain what projects, activities, and other types of work will be funded 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 unplanned in advance; instead, work 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 failure population, both in-service and imminent failures, of these four main LVD substation components in the past five years and what percent of the population does this represent?

A. Based on the five years from 2014 through 2018, the Company has experienced approximately 5.8 LVD transformer failures (approximately 0.55% of population); 27.4 recloser failures (approximately 0.54% of population); and 81 regulator failures (approximately 1.58% of population) per year. These historical failure rates are used to project investment needs going forward in this sub-program.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Substations Demand Failures sub-program?

A. The Company is projecting LVD Substations Demand Failures capital expenditures of $7,001,000, as shown in Exhibit A-33 (RTB-6), line 3, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the four investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 31 below, based on the Company's average failure rates over the historical period of 2014 through 2018.

FIGURE 31
LVD SUBSTATIONS DEMAND FAILURES INVESTMENT CATEGORY
EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Regulators	$1,601,000	81
Reclosers	$600,000	28
Transformers	$2,800,000	6
Other Equipment	$2,000,000	40
Total	**$7,001,000**	

Q. What has been the historical actual spending in the LVD Substations Demand Failures sub-program for the past five calendar years?

A. The historical actual spending in the LVD Substations Demand Failures sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 37.

Q. If spending in any of the five historical years is a significant outlier, please explain why this happened.

A. In 2014, the Company completed an end-of-life rebuild of its Western Avenue substation, resulting in higher spending. In 2016, the Company completed an end-of-life rebuild of its Duck Lake substation, which also caused an increase in spending compared to 2015. In 2017, the Company started a concerted effort to replace Allis Chalmers substation transformers, resulting in an increase in spending in that year and again in 2018. Both end-of-life substation rebuilds and Allis Chalmers transformer replacement work will be performed as part of the LVD Substations Rehabilitation Program in the 2021 test year, as discussed later in my direct testimony.

Q. What is the basis of the Company's requested spending level for LVD Substations Demand Failures in this filing?

A. The Company's requested spending levels for the 2020 bridge year and 2021 test year are based on projected failure rates, which are in turn based on historical failure rates as defined above.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, 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 needed to support capital repair or replacement of failed LVD substation equipment to address interruptions and meet the Company's obligation to serve customers.

4. LVD Metering Demand Failures

Q. Please explain what capital projects, activities, and other types of work will be funded by expenditures in the LVD Metering Demand Failures sub-program.

A. As described in the LVD Metering New Business section of my direct testimony, the LVD Metering Demand Failures sub-program is one component of a single purchase plan, which also includes the LVD Metering Demand Failures sub-program. From this single purchase plan, expenditures are allocated between LVD Metering New Business and LVD Metering Demand Failures based on the historical percentage of actual work that was done in each sub-program. The percentage split is reviewed annually based on prior-year actual work, and the percentages are revised if necessary.

Q. What is the allocation percentage for the 2021 test year?

A. For the 2021 test year, 49% of metering purchases in this purchase plan are allocated to LVD Metering New Business.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Metering Demand Failures sub-program?

A. The Company is projecting LVD Metering Demand Failures capital expenditures of $10,617,000 in the 2021 test year, as shown in Exhibit A-33 (RTB-6), line 4, column (f).

Q. What has been the historical actual spending in the LVD Metering Demand Failures sub-program for the past five calendar years?

A. The Company's historical actual spending in the LVD Metering Demand Failures sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 38.

Q. Please explain year-over-year variation in spending in this sub-program.

A. Total expenditures in both this sub-program and in the LVD Metering New Business sub-program have varied from year to year based on the number of meters the Company has had to purchase. Expenditures in both of these sub-programs also vary from year to year as allocation percentages shift based on the historical actual work of the prior year. As I described in the section of my direct testimony on the LVD Metering New Business sub-program, the Company's total metering purchases varied over the historical period due to the progress of the smart meter deployment program.

Q. What is the basis of the Company's requested spending level in this sub-program?

A. As I described in the section of my direct testimony on the LVD Metering New Business sub-program, the historical average is affected by the fact that many metering purchases were funded through the Company's smart meter deployment program, and smart meters have a higher unit cost than legacy meters. Furthermore, the Company is projecting increases in other areas of reactive Demand Failures investment, particularly LVD Lines Demand Failures and since the LVD Metering Demand Failures sub-program in part supports other Demand Failures investment, the spending level for the LVD Metering Demand Failures sub-program in this filing for the 2020 bridge year and 2021 test year is higher than the historical average as the number of required units increases.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Metering Demand Failures sub-program?

A. Metering is an essential part of the Company's broader requirement to serve customers by replacing failed equipment through the overall Demand Failures Program, the benefits of which were described earlier in my direct testimony. It is essential that the Company replace failed meters to ensure metering accuracy for customers.

5. <u>LVD Transformers Demand Failures</u>

Q. Please explain what capital projects, activities, and other types of work will be funded by expenditures in the LVD Transformers Demand Failures sub-program.

A. As previously discussed, when describing the LVD Transformers New Business sub-program, capital investments in LVD transformers are a single purchase plan that is allocated to three separate sub-programs based on actual historical activity. LVD Transformers Demand Failures accounts for approximately 40% of the projected investment, representing the purchase costs of transformers for Demand Failures projects.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Transformers Demand Failures sub-program?

A. The Company is projecting LVD Transformers Demand Failures capital expenditures of $14,132,000, as shown in Exhibit A-33(RTB-6), line 5, column (f).

Q. What has been the historical actual spending in the LVD Transformers Demand Failures sub-program for the past five calendar years?

A. The Company's historical actual spending in the LVD Transformers Demand Failures sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 39.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Total expenditures in this sub-program have varied from year to year based on the need for LVD transformers. Expenditures in this sub-program also vary from year to year as allocation percentages shift based on the historical actual work of the prior year.

Q. What is the basis for the Company's requested spending level in this sub-program?

A. The requested spending level in this sub-program for the 2020 bridge year and the 2021 test year, while below the historical average, is in line with the most common spending level seen by the Company in recent years. Additionally, the large increase in New Business work affected the allocation percentages for the LVD Transformers sub-programs; the 40% allocation percentage for LVD Transformers Demand Failures is lower than it has been in previous years.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Transformers Demand Failures sub-program?

A. The installation of distribution transformers is an essential part of the Company's other Demand Failures project work; transformers installed in the LVD Transformers Demand

Failures sub-program are primarily used to restore power to customers in situations in which the original transformer has been damaged or is otherwise no longer able to serve the customer.

6. Streetlighting Center Suspension Replacements

Q. Please explain what capital projects, activities, and other types of work will be funded by expenditures in the Streetlighting Center Suspension Replacement sub-program.

A. The Streetlighting Center Suspension Replacement sub-program is a new initiative by the Company, beginning in 2021, to replace existing center suspension street lights with either cobra head street lights or post-top street lights. The Company estimates that it has about 11,000 center suspension street lights to replace, requiring a multi-year effort; the Company plans to completely replace all of these lights by 2029.

Q. Why is the Company proposing to replace center suspension street lights?

A. Center suspension streetlight bulbs are difficult to replace when they burn out. Because they are suspended over the center of the street, frequently over an intersection, replacing them requires traffic to be stopped, with attendant municipal scheduling and permitting concerns. This creates safety concerns. First, crews are exposed to greater risk by having to work in the street, even when precautionary measures are taken, than they would face replacing a light on the side of the road. Second, when a streetlight is out for an extended period of time, due to difficulties in replacement, it creates a public safety concern, as the street is not properly illuminated. This second concern has been highlighted to the Company by the Michigan Municipal Association for Utility Issues, an organization representing municipal governments, many of whom have Company-owned streetlights.

Q. How is this proposed Streetlighting Center Suspension Replacements sub-program related to other Company streetlighting efforts?

A. The Company has been replacing failed cobra head street lights, and will continue to do so, on a reactive basis as part of the LVD Lines Demand Failures sub-program described above. The Company has also recently maintained a sub-program to replace mercury vapor street lights on its system; this effort will be complete in 2020.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the Streetlighting Center Suspension Replacements sub-program?

A. The Company is projecting Streetlighting Center Suspension Replacements capital expenditures of $5,000,000, as shown in Exhibit A-33 (RTB-6), line 6, column (f).

Q. What has been the historical actual spending in the Streetlighting Center Suspension Replacements sub-program?

A. Because this is a new initiative, there is no historical spending.

Q. What is the basis for the Company's 2021 test year spending level in this sub-program?

A. In the 2021 test year, the Company plans to replace between 650 and 700 center suspension streetlights, at an expected average unit cost of $7,500 per replacement. This projected volume of work accounts for anticipated resource availability levels, considering that the Company will be completing other streetlight replacement work in programs such as LVD Lines Demand Failures. In future years, the Company will increase its investment level and replacement rate in order to replace all center suspension streetlights by 2029.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the Streetlighting Center Suspension Replacements sub-program?

A. Center suspension streetlights will be replaced with either cobra head or pole-top streetlights, which can be replaced much more quickly in the case of a burnout. The Company targets replacement of cobra head streetlights within five days of a reported outage. Because of the issues with replacing a center suspension streetlight, a burned-out bulb can take up to six months to replace in some cases. This replacement program will greatly reduce overall burnout replacement times, improving public safety. Additionally, the new lights will be more efficient, and more reliable and less likely to burn out.

Q. How will the Company prioritize which streetlights to replace in the 2021 test year?

A. The Company will prioritize lights for replacement based on a scoring system under development. The Company will build a database of all center suspension streetlights on the system. This database will include information about safety concerns, efficiency of existing lights, and nuisance issues; it will also consider opportunities for synergy such as where multiple lights could be replaced with a single street closure. The Company will prioritize lights for replacement based on this information.

7. <u>Metro Demand Failures</u>

Q. Please explain what capital projects, activities, and other types of work will be funded by expenditures in the Metro Demand Failures sub-program.

A. The Metro Demand Failures sub-program involves the replacement of failed cables, transformers, and civil infrastructure within the Company's six Metro systems. Historically, the Metro Demand Failures sub-program also included work to repair or replace equipment that the Company determined to be at risk of imminent failure, but that work is now included in the new Metro Rehabilitation sub-program discussed later in my direct testimony. Metro Demand Failures costs are highly dependent on contractor construction costs, and are therefore particularly variable, fluctuating based on contractor workload levels. The Company projects its needed investment level in this sub-program based on historical averages and trends. In this filing, spending in Metro Demand Failures is divided into three investment categories: (i) cable failure and replacement; (ii) transformer failure and replacement; and (iii) civil infrastructure failure and replacement.

Q. Why does the Company perform replacement of electrical assets in this sub-program?

A. Electrical assets in Metro vaults may fail due to age, deterioration, standing water, and runoff contaminants (e.g., salt). The most common electrical assets that fail are Metro transformers and cable (primary and secondary). If a primary cable fails, the Company identifies potential switching schemes to immediately restore service to customers. After the fault is isolated and customers are restored, there are times that the Metro system is no longer in an open looped configuration (i.e., no longer has feeds from multiple directions) and needs to be repaired. A design will be created for permanent repairs. By leaving this faulted section isolated for a long period of time, there would no longer be a way to restore service to customers from that direction. If a transformer fails, it is replaced with a spare unit. If a secondary cable fails, a new cable is pulled in a spare conduit adjacent to the failed cable. The failed cable is cut at both ends and removed, creating another spare conduit.

Q. What are the general factors that contribute to the need for investment in the Metro Demand Failures sub-program?

A. Many factors contribute to deterioration of the cabling, equipment, and infrastructure in the Metro systems, including age of the system and weather. The Company commonly sees a number of specific problems caused by the weather including:

- Rain water within vaults, manholes, and conduit/duct banks;
- Snow melt water within vaults, manholes, and conduit/duct banks;
- The freezing of this water due to the area's climate;
- The effects of the snow melt substances used to help clear roads; and
- The effects of the heavy snow removal equipment over the surfaces of the vaults/manholes.

These factors lead to a number of issues, including damaged cable, damaged/crushed duct banks, deteriorated manhole/vault roofs, sunken/deteriorated manhole access, and rusted/deteriorated vault hatches and vents.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the Metro Demand Failures sub-program?

A. The Company is projecting Metro Demand Failures capital expenditures of $3,100,000, as shown in Exhibit A-33 (RTB-6), line 7, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the three investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 32 below.

FIGURE 32
METRO DEMAND FAILURES INVESTMENT CATEGORY EXPENDITURES

Investment Categories	Capital
Cable failure and replacement	$2,237,000
Transformer failure and replacement	$629,000
Civil infrastructure failure and replacement	$234,000
Total	**$3,100,000**

Units are not conducive to the Metro Demand Failures investment categories, as individual projects may involve replacements in more than one category and stretch across more than one year.

Q. What has been the historical actual spending in the Metro Demand Failures sub-program for the past five calendar years?

A. The historical actual spending in the Metro Demand Failures sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 42.

Q. If spending in any of the five historical years is a significant outlier, please explain why this happened.

A. In 2016, the Company invested more money than average in this sub-program to address issues with civil and electrical infrastructure in the Flint and Jackson Metro systems. That work included addressing imminent failures, which in this filing would be addressed instead in the Metro Rehabilitation sub-program.

Q. What is the basis of the Company's requested spending level for Metro Demand Failures in this filing?

A. The Company's requested spending level for the 2020 bridge year and the 2021 test year is based on historical trends for this sub-program.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the Metro Demand Failures sub-program?

A. The projected test year amount provides for the level of investment necessary in Metro Demand Failures needed to support capital repair or replacement of failed Metro equipment to address interruptions and meet the Company's obligation to serve customers.

D. Asset Relocations Program

Q. What is the purpose of the Asset Relocations Program?

A. The Asset Relocations Program includes capital investments to relocate electric assets to accommodate road, building, and other third-party construction projects, as well internal Company projects. The cost of relocating lines in the road right-of-way ("ROW"), and in some cases on private property, is typically the responsibility of the Company. The Asset Relocations Program includes the following sub-programs: (i) LVD Asset Relocations; (ii) HVD Asset Relocations; and (iii) Metro Relocations.

Q. To what extent is the Asset Relocations program "unplanned?"

A. Most Asset Relocations work is entirely "unplanned," in that it is reactive to requests from third parties external to the Company. As I will discuss in the Metro Asset Relocations section, some projects in the Metro Asset Relocations sub-program may be known further in advance given the relatively complex nature of such projects.

Q. What is the Company's total projected investment in the Asset Relocations Program in this case, and what is the basis for this level of investment?

A. As previously noted, the settlement in Case No. U-20134 approved $24,000,000 in Asset Relocations spending for the 2019 test year, with the stipulation that the Company could use deferred accounting for any New Business spending in 2019 that exceeded that amount.

As shown in Exhibit A-34 (RTB-7), line 4, column (c), the Company's 2019 spending was projected to be $44,512,000. Spending in the Asset Relocations Program remains fairly level from 2019 through 2020 to 2021, and for the 2020 bridge year in this filing, the Company projects to spend $41,675,000, as shown in Exhibit A-34 (RTB-7), line 4, column (d). For the 2021 test year, the Company projects to spend $45,976,000, as shown in Exhibit A-34 (RTB-7), line 4, column (f). Projected spending is explained in greater detail in the Asset Relocations sub-program sections below.

1. LVD Asset Relocations

Q. Please explain what capital projects, activities, and other types of work will be funded by expenditures in the LVD Asset Relocations sub-program.

A. The LVD Asset Relocations sub-program responds to internal and external requests to relocate LVD lines. This sub-program also includes "make ready" work to prepare LVD poles for third-party attachments; make ready work can include physical relocation of a pole, but it may also include work to strengthen a pole to allow it to support additional weight. State and municipal agencies, private property owners, and other Consumers Energy departments make requests for relocations; in addition, telecommunications companies request make-ready work so they can attach phone and cable lines and cellular equipment on poles. The sub-program includes any reimbursements from the requesting party, which directly offset expenses incurred to perform the work. The annual sub-program expenditures are based on the cost to relocate less the reimbursements received. Due to the demand-based nature of this sub-program, the Company does not follow a specific planning cycle, and generally cannot plan relocation projects far in advance. Each request contains different timelines and requirements based on the nature of the request, and the Company constantly adjusts timing of projects to meet customer schedules. The Company projects its spending levels based on historical activity, while also accounting for observed trends, particularly related to economic activity.

Q. How does the Company identify projects that need to be completed in the LVD Asset Relocation sub-program?

A. The activity in this sub-program is entirely driven by requests from both external and internal stakeholders. For all project requests, a party submits a request that includes timelines for completion if applicable, the project purpose, contact information, and any other pertinent information. For many municipal projects and large internal projects, the Company holds site meetings to gather further information.

Q. How does the Company use information provided by a party requesting relocation?

A. The Company studies the descriptions, maps, surveys, designs and/or other documentation provided by the requester and combines that documentation with internal maps and field measurements to determine what Company facilities, if any, require relocation and where assets should be relocated.

Q. What actions does the Company take when relocation is required?

A. For requests requiring significant relocation or changes to the LVD system, the Company evaluates the proposed changes against a load flow analysis and reliability assessment to determine if relocation will have an adverse effect on the system. If a proposed relocation will negatively impact the reliability or capacity of the LVD system, changes would be necessary. For example, a customer could request relocation of facilities to the edge of their property line, but that move could put the facilities in dense vegetation, making the line less accessible and requiring more line clearing. In that case, the Company would work with the customer to find a better route that meets the customer's needs without impeding reliability. On the other hand, if the relocation significantly changes the length of conductor, it may create a capacity issue and the conductor would need to be upgraded in size.

Q. Please describe the types of projects that the Company includes in the LVD Lines Relocation sub-program.

A. The Company categorizes requests for relocation as coming from either: (i) government agencies; (ii) private property owners; or (iii) other departments within Consumers Energy.

Q. What is the nature of relocation requests made by government agencies?

A. Government agency-requested LVD relocations can fluctuate throughout the year for many types of projects, such as road and bridge widening or improvements, repairs to municipal facilities, and street light and traffic signal modifications. Road and bridge widening or improvements include moving poles, wires, and other LVD equipment due to changes to the road location and grade and to provide proper clearance for any large equipment that the road construction contractors have onsite. Government agency timelines can vary widely based on size and complexity.

Q. What is the nature of relocation projects requested by private property owners?

A. Private property owner requests vary widely based on the type of project and project timeline. Property owners request LVD relocations for building additions, logistics, landscaping, or other construction projects. Private landowners often request relocation of overhead lines out to the road or underground, particularly to facilitate moving large farm equipment. Residential customers often request relocation of LVD lines to facilitate building an addition, pool, shed, barn, or landscaping feature such as a pond or berm. Commercial customers often request relocation of poles from a parking lot or other area.

Q. What is the nature of relocation requests generated within the Company?

A. Relocation requests within the Company may come from the HVD Planning group, the Substation Planning group, or the Metro Planning group, in order to facilitate projects planned by their respective groups.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Asset Relocations sub-program?

A. The Company is projecting LVD Asset Relocations capital expenditures of $41,226,000, as shown in Exhibit A-34 (RTB-7), line 1, column (f).

Q. What has been the historical actual spending in the LVD Asset Relocations sub-program for the past five calendar years?

A. The Company's historical actual spending in the LVD Asset Relocations sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 44.

Q. If any of the five historical years is a significant outlier, please explain why this happened.

A. Since investment in this sub-program is heavily dependent on requests for relocation, the cost of a given relocation project can vary widely, from as low as $1,000 to as high as $1,000,000. The Company saw a marked increase in requests for make-ready projects starting in the summer of 2018, causing spending on such projects to increase substantially going forward from that point, a trend which carried into 2019. Additionally, the Company needed to relocate an increasing number of LVD lines in 2019 to accommodate HVD projects, particularly in locations where LVD lines are underbuilt on HVD structures.

Q. What is the basis for the Company's requested spending level in this sub-program?

A. As discussed already, the Company saw a large increase in requests beginning in the summer of 2018. The Company is projecting that make-ready work will not continue to grow rapidly, but will remain at elevated levels compared to historical averages, especially as telecommunications companies install 5G cellular equipment on poles. The Company also anticipates an increase in LVD lines that need to be relocated to accommodate HVD projects, since the Company plans to increase its work on the HVD system, especially in the HVD Lines Reliability and HVD Lines Rehabilitation sub-programs. These trends informed the Company's projected needs for the 2020 bridge year and the 2021 test year.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Asset Relocations sub-program?

A. This sub-program primarily functions to serve customer requests, whether they are internal or external. However, every time old or obsolete equipment is replaced through this sub-program, reliability improves because of the new equipment and the latest standards implemented at the time. Relocations performed for HVD or substation work allow maintenance work on the facilities before a failure causes an outage. Preventatively preparing the LVD system for this work can save many customer minutes, as an outage would typically de-energize more than one circuit on these systems, with an average of 1,000 customers per circuit for two hours or more. When LVD projects are able to support a planned load transfer for HVD and substation work, the Company can perform the work in a controlled environment with little or no outage to customers. Additionally, as mentioned above, some relocation requests provide clearance for large equipment like farm machinery and road construction equipment. Without sufficient clearance, that machinery may contact the LVD system, causing an outage, putting the operator or other members of the public in danger, and causing thousands of dollars of damage. The LVD Lines Relocation sub-program ensures that municipal requests are completed by the deadline. Ultimately, if the Company does not complete LVD Lines Relocation work for any reason, it could face legal consequences and reputational damage.

2. HVD Asset Relocations Sub-Program

Q. Please explain what capital projects, activities, and other types of work will be funded by expenditures in the HVD Asset Relocations sub-program.

A. The HVD Asset Relocations sub-program includes the capital investments necessary to facilitate non-reimbursable relocations of HVD lines required to meet usage of public ROW and required Michigan Electric Transmission Company ("METC") project work. The cost of relocating lines in road ROW, or in some instances on private property, is typically the responsibility of the Company. Due to the emergent nature of the work, projects funded by this program are generally not known well in advance, so projected funding is based on historical averages and adjusted for observed trends.

Q. Which parties typically request HVD Asset Relocations projects?

A. There are four general categories of parties that may request HVD Asset Relocations projects: municipalities and other government agencies, METC, private landowners, and internal Company departments.

Q. Please explain each category.

A. Municipalities and other government agencies request HVD Asset Relocations to facilitate their civil engineering projects, such as road and bridge widening and improvements; repairs to municipal facilities; work on water and sewer lines; and street light and traffic signal modifications. The HVD Asset Relocations allow those agencies to access their facilities without having to work around HVD infrastructure. Relocations may be temporary or permanent.

METC may request HVD Asset Relocations to accommodate their transmission projects. For example, the Company may have HVD lines that are attached to METC structures below transmission lines. Depending on the nature of the project, METC may reimburse the Company for associated costs. This is handled on a case-by-case basis.

Private landowners and businesses request HVD Asset Relocations to accommodate additions, landscaping, and other construction projects on their property. One relatively common request is for overhead lines to be repositioned to allow for building additions.

Internal Company departments may require HVD Asset Relocations to accommodate their own projects that they are planning.

Q. What are some examples of HVD Asset Relocations projects?

A. The Company relocated three structures on the 46 kV Cascade line in Kent County to accommodate road widening by the Kent County Road Commission. The Company also removed four structures and installed seven new structures on the Allendale 46 kV line in Ottawa County to accommodate development of a property owner's land.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the HVD Asset Relocations sub-program?

A. The Company is projecting HVD Asset Relocations capital expenditures of $900,000, as shown in Exhibit A-34 (RTB-7), line 2, column (f).

Q. What has been the historical actual spending in the HVD Asset Relocations sub-program for the past five calendar years?

A. The Company's historical actual spending in the HVD Asset Relocations sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 45.

Q. If any of the five historical years is a significant outlier, please explain why this happened.

A. As already discussed, investment in this sub-program is heavily dependent on requests for relocation. The cost of an individual relocation project can vary substantially, and, given the relatively low volume of work in this sub-program, a single large project may cause spending to rise in a particular year.

Q. What is the basis of the Company's requested spending level in this sub-program?

A. As discussed above, projected spending in this sub-program is based on historical spending, accounting for observed trends. The requested spending level in this program for the 2020 bridge year and the 2021 test year is consistent with historic spending levels. Spending in this sub-program has shown an upward trend in recent years.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the HVD Asset Relocations sub-program?

A. Although the primary purpose of this sub-program is to accommodate the needs of customers and other external parties, the sub-program also helps improve reliability through the installation of new equipment. When the Company replaces old or obsolete equipment with new equipment as part of a relocation project, reliability is improved since the new equipment has up-to-date design standards and less general wear and tear.

3. <u>Metro Asset Relocations</u>

Q. Please explain what capital projects, activities, and other types of work will be funded by expenditures in the Metro Asset Relocations sub-program.

A. The Metro Asset Relocations sub-program responds to both internal and external requests to relocate subterranean civil and subterranean or padmounted electric facilities or adjust manhole chimneys and castings due to road grade changes, either in public ROWs or on private property, that are part of the Company's Metro system in core urban areas. The Company generally treats externally-requested Metro relocation projects on a demand basis, with the Company making it a priority to meet mutually agreed upon deadlines and milestones, and to perform the required work within the requested ROW. Internally-requested projects, requested by other departments within the Company, may be planned further in advance, rather than on a demand basis.

Q. What is the typical nature of external relocation requests in the Metro Asset Relocations sub-program?

A. External relocation requests come from state agencies, municipalities (especially Downtown Development Authorities and Tax Increment Finance Authorities), and private developers. State agencies and municipalities may request relocations to accommodate for an upcoming civic improvement work for a specific ROW. Typical improvements include storm and sanitary sewers, water mains, street improvements, and streetscapes. Municipalities, Downtown Development Authorities, Tax Increment Finance Authorities, and private developers may request relocations to convert overhead electric systems to subterranean civil and electrical systems, generally to improve aesthetics. These requests typically require the customer to provide a non-refundable engineering deposit for the

Company to perform a feasibility study to find a subterranean path for the civil infrastructure system.

Q. What is an example of a recent externally requested Metro Asset Relocations project?

A. A customer in Kalamazoo approached the Company about the cost to convert existing overhead electrical assets in the ROW to underground assets for aesthetic reasons. Due to the congestion of other utilities in the ROW, extension and expansion of the metro system was chosen. An external civil engineering firm provided a feasibility study, as contracted by the Company, and based on this study the Company elected to construct a new duct bank on one lane of a three-lane road.

Q. What is the Company's process for planning Metro Asset Relocations projects in response to internal requests?

A. Projects triggered by an internal request are considered during the Metro planning process, which takes place in July and August of each year. Company circuit engineers with responsibility for planning and design of the affected Metro system area prepare scope documents and estimated project costs during this process.

Q. How does the Company project necessary investment in the Metro Asset Relocations sub-program?

A. Since much of the sub-program is demand-based, the Company's spending in the Metro Asset Relocations sub-program due to external requests typically rises and falls in correlation with Michigan's overall economic health. Metro Asset Relocations is therefore challenging to forecast, since it is contingent on state agencies and municipalities contacting the Company in advance of the desired date of service, and the municipality providing the required information and their portion of work to coincide with that desired date. The

Company therefore uses analysis of historical trends and data to make yearly spending projections and as a basis for future investment plans. The Company plans this sub-program conservatively by starting with a historic average baseline and then reevaluates and adjusts investment levels up (or down) from that baseline as additional projects and commitment levels become firm.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the Metro Asset Relocations sub-program?

A. The Company is projecting Metro Asset Relocations capital expenditures of $3,850,000, as shown in Exhibit A-34 (RTB-7), line 3, column (f).

Q. What has been the historical actual spending in the Metro Asset Relocations sub-program for the past five calendar years?

A. The Company's historical actual spending in the Metro Asset Relocations sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 46.

Q. If any of the five historical years is a significant outlier, please explain why this happened.

A. Investment in this sub-program is heavily dependent on volume and complexity requests for relocation. The Company's high spending level in this sub-program in 2015 was driven by the need to coordinate utilities for the Michigan Avenue/Pearl Street reconstruction project in downtown Jackson.

Q. What is the basis for the Company's requested spending level in this sub-program?

A. The five-year historical average in this sub-program is skewed by the abnormally high spending in 2015. As noted earlier, the Company based its projected investment for the

2020 bridge year and 2021 test year in this sub-program on historical trends, and actual spending in this sub-program has shown a downward trend since 2015.

Q. Are there any prioritized projects that make up the requested spending level in the Metro Asset Relocations sub-program?

A. For the 2021 test year, the Company has already identified the following Metro Asset Relocations projects:

- The City of Flint has requested coordination from the Company in rebuilding a downtown brick street. Coordination will allow the Company to install new civil infrastructure in this ROW without incurring restoration costs; and
- A hospital in Kalamazoo is requesting that the Company vacate its overhead facilities in a street ROW, requiring reconstruction of those facilities to the Metro system, given the congestion of other utilities in this street ROW.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the Metro Asset Relocations sub-program?

A. Although the primary purpose of this sub-program is to accommodate the needs of customers and other external parties, the sub-program also helps improve reliability through the installation of new equipment. When the Company replaces old or obsolete equipment with new equipment as part of a relocation project, reliability is improved since the new equipment has up-to-date design standards and less general wear and tear.

E. Reliability Program

Q. What is the purpose of the Reliability Program?

A. The purpose of the Reliability Program is to ensure the long-term safe and reliable operation of the electric distribution system. Capital expenditures in the Reliability Program include investments to install, upgrade, and rehabilitate LVD and HVD lines, LVD and HVD substations, Metro underground assets, and protective relay systems. The Reliability Program also includes capital expenditures to modernize the electric grid, including investments in grid infrastructure improvements (i.e., Grid Modernization) and battery storage. The sub-programs in the Reliability Program are: (i) LVD Lines Reliability; (ii) HVD Lines Reliability; (iii) LVD Substations Reliability; (iv) HVD Substations Reliability; (v) Grid Modernization; (vi) System Protection; (vii) LVD Repetitive Outages; (viii) Metro Reliability; (ix) HVD Lines and Substations Rehabilitation; (x) LVD Substations Rehabilitation; (xi) LVD Lines Rehabilitation; (xii) Metro Rehabilitation; and (xiii) Grid Storage.

Q. To what extent are Reliability Program investments "planned?"

A. Each Reliability sub-program consists primarily of investments that are discretionary, in that they do not respond to an emergency, meaning the Company has some ability to prioritize and reprioritize its projects in these sub-programs. As I discussed earlier in my direct testimony when describing deterioration on the distribution system, the Company has a large volume of distribution assets that would benefit from Reliability Program investments beyond what the Company plans for the 2021 test year. Because of this, the Company may, during the 2021 test year, pull forward projects that originally were not scheduled until later, if conditions warrant.

Q. Has the Company made any changes in this filing in how it classifies Reliability projects?

A. Yes. As I discussed in the Demand Failures Program section of my direct testimony, the Demand Failures Program historically included spending on imminent failures. That spending is now included in the Reliability Program, in the Rehabilitation sub-programs.

Q. Has the Company made any other changes in what is included for the 2021 test year?

A. Yes. The Company has been upgrading communications devices at its substations, replacing obsolete devices no longer compatible with the telecommunications provider, in the Substations Communications Upgrades sub-program. As shown in Exhibit A-31 (RTB-4), line 7, column (d), the Company is spending $2,100,000 during the 2020 bridge year on this project, after which the project will be complete. There is no spending in this area in the 2021 test year.

Q. What is the Company's total projected investment in the Reliability Program in this case, and what is the basis for this level of investment?

A. As previously noted, the settlement in Case No. U-20134 stipulated that the Company would spend at least $200,000,000 in the Reliability Program the 2019 test year. As shown in Exhibit A-31 (RTB-4), line 16, column (c), the Company's 2019 spending was projected to be $230,207,000. That total includes $20,473,000 in LVD Lines Rehabilitation spending, as shown in Exhibit A-31 (RTB-4), line 13, column (c). However, the settlement amount did not include any Rehabilitation spending, which was considered Demand Failures spending in Case No. U-20134. If the 2019 LVD Lines Rehabilitation spending is excluded, then the Company's 2019 Reliability spending is $209,734,000. In the 2020 bridge year, the Company is projecting $201,165,000 in total Reliability spending, as shown in Exhibit A-31 (RTB-4), line 16, column (d), consistent with the total Reliability amount approved in Case No. U-20134. For the 2021 test year, the Company projects to spend $331,234,000, as shown in Exhibit A-31 (RTB-4), line 16, column (f). Projected 2021 spending is explained in greater detail in the Reliability sub-program sections below.

1. LVD Lines Reliability

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the LVD Lines Reliability sub-program.

A. The LVD Lines Reliability sub-program includes projects to ensure the long-term safe and reliable operation of the Company's LVD lines. The sub-program includes a diverse range of projects that are specifically designed to address concerns on a given circuit or circuits. The LVD Lines Reliability sub-program consists of four investment categories: (i) targeted circuit improvements; (ii) pole replacements; (iii) circuit exit enhancements; and (iv) ROW projects.

Q. What does the Company include in targeted circuit investments?

A. Targeted circuit improvements include several project types with customized solutions to address specific reliability concerns. The most common strategies employed are: (i) reducing the amount of non-standard voltage on the distribution system; (ii) first zone interruption reduction; and (iii) zonal targeted investments.

Q. How does the Company reduce the amount of non-standard voltage?

A. The Company converts distribution circuits and substations energized at non-standard voltages to the three standard operating voltages that Consumers Energy operates. The Company currently operates 13 general distribution voltage systems; the three standard operating voltages are 4.8/8.32kV, 7.2/12.47kV, and 14.4/24.9kV grounded-wye. Customer-dedicated systems are not within the scope of this category.

Q. What are the benefits reducing the amount of non-standard voltage?

A. The benefits of reduction are:

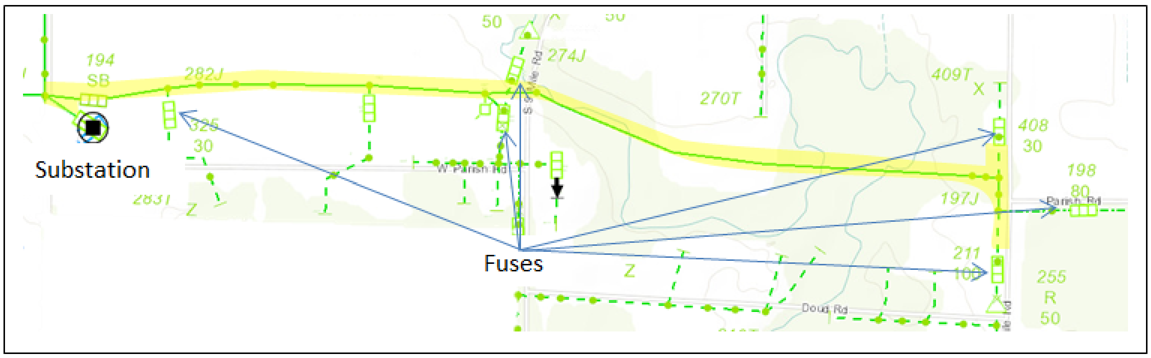
- **Safer operating systems –** Grounded-wye operating systems are safer to operate than non-standard Delta systems. Delta systems require two-phase ground faults to be present before the phase protective device operates/trips, which means a downed Delta wire will not trip a primary protective device until a second phase fault develops;

- **Reduced system losses and increased system line capacity –** Converting Delta systems to grounded-wye reduces load current on primary lines, thereby increasing available line capacity. For the same electric load, the grounded-wye system will carry 58% of the load current that the Delta system carries (e.g., a 400 Amp rated conductor carrying 360 Delta Amps (90% loaded) will carry 208 Wye Amps (52% loaded) after the conversion). Since the amount of loss in an electric system is proportionate to the square of the load current, reducing the load current by voltage conversion lowers the electric loss associated with that portion of the electric system. Further loss reduction is typically realized through voltage conversion as older transformers and isolators are replaced as part of the voltage conversion project;
- **Improved system reliability** – Voltage conversions on the distribution lines are similar to pole top rehabilitation work, in that older equipment is replaced with new, which allows the Company to realize corresponding SAIDI and SAIFI improvements;
- **Reduced number of interrupted customers for single-phase faults –** When a single-phase fault occurs on the Delta system, two primary phases trip, interrupting two-thirds of the customers; when a single-phase fault occurs on the grounded-wye system, only one phase trips, interrupting one-third of the customers;
- **Increased system transfer capability** – Circuit conversions create the opportunity to improve transfer capability between like systems and build a platform for increased distribution automation and smart grid systems; and
- **Reduced equipment inventory –** Eliminating the non-standard line transformer inventory would not significantly increase the cost to maintain the standard voltage transformer inventory. The non-standard line transformer population is very small compared to the standard transformer population, so the re-order points for standard voltage equipment would remain the same. It would, however, reduce and eventually eliminate the need to maintain non-standard line transformer inventory.

Q. Please explain first zone interruption reduction.

A. This category reduces interruptions in the first protective zone on distribution circuits. The first zone is between the substation and the first protective devices that isolate this first section of distribution circuit from other segments of circuit. Below in Figure 33, the first zone is represented by the highlighted section. LVD circuit planners identify electric assets within the first zone that require replacement or the addition of protective schemes. Items identified for replacement include, but are not limited to, poles, cross-arms, pins and insulators, lightning arrestors, non-standard equipment, and cutouts. Protective schemes, such as fuses or reclosers, are added or upgraded to reduce the size of the first zone and reduce the number of customers that are impacted by an interruption.

FIGURE 33
ILLUSTRATION OF FIRST ZONE INTERRUPTION REDUCTION



Q. Please explain zonal targeted investments.

A. Zonal targeted investments improve the reliability of the Company's LVD system by reducing the likelihood of an additional interruption over the next five years or more. A zone for targeted improvement can include multiple protective device zones or a single protective device zone. When the Company is aware that a circuit has deficiencies, based on outage data, then the Company inspects the overhead lines on affected circuits to identify appropriate solutions to improve reliability on those circuits. Solutions in zonal targeted investments include:

- Upgrading lightning protection to meet standards – Company standards provide for lightning arresters every 1,300 feet on LVD lines to protect the system from lightning damage;
- Replacing equipment at the end of expected life, including cross-arms, switches, and conductors (overhead and underground);
- Installing new system protection devices, including fuses, switches, and reclosers;

- Upgrading conductors to tree wire or aerial spacer cable to provide better tree protection;
- Restoring underground cable that is no longer looped to reestablish redundancy; and
- 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).

Q. What work does the Company do in the pole replacement investment category in the LVD Lines Reliability sub-program?

A. Pole replacements in the LVD Lines Reliability sub-program are completed in response to prior inspection results that identified poles at risk of failure.

Q. What work does the Company include in circuit exit enhancements?

A. The Company installs circuit exit switches on circuits; circuit exit switches are installed 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 or land rights is essential to enabling LVD lines and substations projects across multiple capital sub-programs.

Q. How does the Company identify reliability issues that may warrant an LVD Lines Reliability project?

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 based on the objectives of improving reliability.

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, using the strategies outlined above.

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., SAIFI, CAIDI, and Customers Experiencing Multiple Interruptions ("CEMI")) to be calculated at varying levels of granularity. By combining data from various sources, the RAE can also construct a complete timeline for all incidents from initial outage to final restoration. This detailed timeline breaks down an outage into analysis, dispatch, travel, and repair process steps and calculates the time spent in each step. The RAE also includes other sources such as forestry clearing data, callout success rates, and historic project spending. These can be combined with other data to analyze reliability. The RAE also produces monthly zonal analysis data that is reviewed by each area's LVD circuit planner. This data is analyzed to determine zonal impact to LVD system reliability.

Q. What conclusions does the Company draw from this RAE analysis?

A. By analyzing historical outage minutes across the grid, identifying trends, and assessing zones with the greatest potential reliability improvement, RAE provides a ranking of zones to target to maximize SAIDI reduction. Once reliability inputs are used to identify zones to target on the LVD system, reliability projects are developed, evaluated, and prioritized to develop an investment plan that maximizes the reliability benefit for customers.

Q. What other information does the Company consider when identifying potential LVD Lines Reliability projects?

A. The Company considers other circuit characteristics, such as car-pole accident history and downed wires, to potentially modify and reprioritize the list of LVD Lines Reliability projects, and to optimize spending, as discussed earlier in my direct testimony.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Lines Reliability sub-program?

A. The Company is projecting LVD Lines Reliability capital expenditures of $44,929,000, as shown in Exhibit A-31 (RTB-4), line 1, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the five investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 34 below.

FIGURE 34
LVD LINES RELIABILITY INVESTMENT CATEGORY
EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Targeted circuit improvements	$25,885,000	144
Pole replacements	$14,880,000	51 projects/1,604 poles
Circuit exit enhancements	$1,844,000	78
Right of way	$2,321,000	n/a
Total	**$44,929,000**	

Q. What has been the historical actual spending in the LVD Lines Reliability sub-program for the past five calendar years?

A. The Company's historical actual spending in the LVD Lines Reliability sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 8.

Q. If spending in any of the five historical years is a significant outlier, please explain why this happened.

A. The Company spent less in the Reliability capital program, including in LVD Lines Reliability, in 2015 due to a need to rebalance resources to address an increase in New Business, Asset Relocations, and Demand Failures needs in 2015, as shown in Exhibit A-29 (RTB-2), lines 7, 43, and 47, columns (c) and (d).

Q. What is the basis for the Company's requested spending level in this sub-program for the 2021 test year?

A. The Company's projected spending level in this sub-program is within the range of historical spending amounts, and when compared to the past three years is in line with the overall distribution strategy described in my direct testimony of increasing investment in reliability of LVD lines. Additionally, the Company's expenditures in the LVD Lines

Rehabilitation sub-program represent further substantial investments in the reliability of the LVD lines system.

Q. What are the historical unit costs for each of the LVD Lines Reliability investment categories?

A. Historical unit costs for each category are provided in Figure 35 below:

FIGURE 35
LVD LINES RELIABILITY INVESTMENT CATEGORY UNIT COSTS

Investment Categories	*2014*	*2015*	*2016*	*2017*	*2018*
Targeted circuit improvements	n/a	n/a	n/a	$80,400/project	$206,000/project
Pole replacements	$6,000/pole	$4,800/pole	$4,400/pole	$4,700/pole	$7,300/pole
Circuit exit enhancements	n/a	n/a	n/a	$32,800/project	$44,000/project

There are no unit costs for the ROW investment category. Targeted circuit improvements and circuit exit enhancements were not tracked as investment categories prior to 2017, so unit cost data from prior to that year do not exist.

Q. Please explain any variation in unit costs over time.

A. Pole replacement and targeted circuit improvement unit costs began increasing in 2018, primarily due to labor cost increases. Beginning in 2018, the Company began adding a third person to its line crews to act as a safety spotter during construction. The Company also experienced an increase in contractor costs beginning in 2018. During that year, the Company agreed to new zonal contract rates; these new rates were higher than historical rates due to tight labor market conditions. In addition, for targeted improvements, specific individual projects can vary widely in cost from project to project based on specific project conditions, and as a result the year-end per-unit average cost can also vary.

Q. Are there any prioritized projects that make up the requested spending level in the LVD Lines Reliability sub-program for the 2021 test year?

A. The Company has identified 51 pole replacement projects, totaling 1,604 poles, as listed in Exhibit A-42 (RTB-15), page 1, line 14, through Exhibit A-42 (RTB-15), page 2, line 20. The Company has identified 144 targeted circuit improvement projects, as listed in Exhibit A-42 (RTB-15), page 2, line 21, through Exhibit A-42 (RTB-15), page 5, line 18. The Company has identified 78 circuit enhancement projects, as listed in Exhibit A-42 (RTB-15), page 5, line 19, through Exhibit A-42 (RTB-15), page 6, line 46. The Company developed concept approvals for many of these projects, as listed in Exhibit A-41 (RTB-14), lines 3 and 4.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Lines Reliability sub-program?

A. LVD Lines Reliability projects form a critical part of the Company's glidepath for reaching 170 SAIDI minutes in 2025. Specific contributions of the LVD Lines Reliability sub-program to that glidepath were shown in Figure 2 earlier in my direct testimony. In addition to driving system-wide SAIDI improvements, LVD Lines Reliability projects consistently provide immediate benefits on the circuits or zones in which they are completed. Figure 36 below illustrates zonal performance improvements following targeted circuit improvement projects in 2017 and 2018, covering the period since the Company began targeting zones through the targeted circuit improvement investment category.

FIGURE 36

AGGREGATED IMPACT OF TARGETED CIRCUIT IMPROVEMENTS ON ZONAL PERFORMANCE

			Outages		
Project Year	Zones Targeted	Miles Targeted	Prior 3-Year Average	Post 1-Year/2-Year Average	Percent Improvement
2017	166	293	186	86	54%
2018	164	302	184	107	48%

Specific examples of these projects have included:

- **Wyoming Park substation, Porter circuit, first zone** – The substation recloser experienced two to four outages per year due to equipment failure beginning in 2014, interrupting approximately 940 customers with each outage. In 2017, the Company replaced poles, pole top structures, and conductor in this zone. Subsequently, those customers experienced no interruptions in 2018 or 2019 due to this equipment issue, saving approximately 815,000 annual customer outage minutes; and

- **Levely substation, Sturgeon circuit, zone 860** – The fuse at zone 860 experienced eight outages in 2017 and three outages in 2018 due to tree issues, interrupting approximately 250 customers. In 2018, the Company upgraded the three-phase conductor to more robust tree wire over a one-mile stretch. Subsequently, those customers experienced no interruptions in 2019 due to this issue, saving approximately 280,000 annual customer outage minutes.

2. <u>HVD Lines Reliability</u>

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the HVD Lines Reliability sub-program.

A. Work in the HVD Lines Reliability sub-program consists of four investment categories: i) HVD line rebuilds – complete overhead line rebuilds including insulator, conductor, cross-arms, and structure replacements; ii) pole-top rehabilitations, which include replacing deteriorated cross-arms, insulators, cross-arm braces, and hardware on pole tops as necessary; iii) pole replacements; and iv) switch projects, including SCADA additions. The Company customizes its responses to poorly performing lines individually, based on the configuration, construction style, inspection results, and other key factors. Lines that meet modern construction and design standards and have standard conductors will primarily receive pole top rehabilitation, while lines that utilize non-standard construction or equipment will typically be rebuilt. Occasionally, lines that meet modern standards will need to be rebuilt; this could be due to access issues or upgrades that could improve operational flexibility. As part of HVD line rebuild and pole top rehabilitation projects, the Company clears the line ROWs and addresses hazard trees from a forestry perspective in advance of the line work. This line clearing forestry work is included as part of the project capital expenditures. The Company initiates projects to upgrade assets to improve resilience to deterioration and weather.

Q. Please further explain line rebuilds.

A. A rebuild involves replacing every insulator, conductor, cross-arm, cross-arm brace, piece of hardware, and structure within the line section identified in the scope of a project. The Company identifies lines or line sections as needing a rebuild when it would be more effective to rebuild the entire line or line section than to replace individual components through rehabilitation due to its deteriorated condition, and/or the line is built with outdated construction standards such as unshielded, small single layer conductor, and/or copper conductor. The Company's experience with line rebuilds has demonstrated that completing rebuild work on such lines dramatically reduces outages on those lines.

Q. Please further explain pole-top rehabilitation.

A. The Company performs HVD pole top rehabilitation projects to improve the condition of deteriorated cross-arms, insulators, cross-arm braces, and hardware on pole tops through the replacement of those components as necessary. For the HVD line section identified for these projects, the Company utilizes qualified journeyman line workers who perform a visual inspection of every structure within the defined project scope to determine if there are anomalies with the components on a structure. If anomalies (split or cracked cross-arm, chipped, cracked or tipped insulator, loose or detached cross-arm brace, etc.) are identified, the Company may replace the entire pole top assembly (all of the previously stated components), or only the component(s) requiring replacement. When pole top assembly components are replaced, they are brought up to current Consumers Energy standards. For example, pin-type insulators are replaced with post-type insulators. Additionally, to maximize efficiency and reliability improvement of an HVD line section through a pole top rehabilitation project, the Company will be performing a pole inspection of the line section if the last pole inspection was performed six or more years prior. Structures identified through this inspection process that require replacement within the line section of the project will be replaced along with the rehabilitation project.

Q. Please explain the Company's pole inspection methodology and pole replacement criteria.

A. Details on the Company's inspection and replacement criteria are provided in Exhibit A-43 (RTB-16).

Q. How does the Company determine which HVD line sections should be addressed with projects in this sub-program?

A. The Company focuses on lines that are consistently poor performers and looks for the best remediation strategy to prevent future outages in the most economical way. While continuously monitoring the reliability of the HVD lines system, the Company also performs an annual review of its HVD line sections, considering both line performance and line condition, to determine which lines and line components need to be addressed in the next year or years, as some projects may be large enough to span multiple years.

Line performance is an aggregate of both the number of incidents on the line segment as well as the number of customer minutes generated by an incident to the line segment. The primary driver for investment decisions is line performance. Therefore, lines with the highest average of incident rates and customer minute totals in a rolling three-year period are given higher priority for remediation. Additionally, line condition is taken into consideration based on high pole rejection rate per the pole inspection program and if the line is of non-standard (outdated) construction.

Occasionally, projects outside of the worst performers are worked on based on completing multi-year plans, rapidly degrading reliability, customer commitments, or other unique circumstances. Unique circumstances are typically the result of addressing a reliability need as an ancillary benefit during a project for which the primary benefit may be capacity or asset relocation focused.

Q. Please describe modeling efforts in support of project prioritization in this sub-program?

A. The Company uses a model that specifically addresses HVD Line system performance. The model prioritizes HVD line segments based on actual outage history, conductor type, shielding, and the potential customer impact if this line segment were to fail. It provides a first cut for Company engineers regarding where preventative outage work would be most beneficial. This model is used to help select some projects and to validate projects that were previously identified.

Q. Does the Company rely solely on this or any model to determine which line segments are to be rebuilt or rehabilitated?

A. No. Company engineers will review the output of sorting historic HVD line outages by number of incidents and outage minutes along with the output of this model and then apply their knowledge of the system condition, including recent inspection information, and may also perform a field assessment before making a final determination.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the HVD Lines Reliability sub-program?

A. The Company is projecting HVD Lines Reliability capital expenditures of $78,129,000, as shown in Exhibit A-31 (RTB-4), line 2, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the three investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 37 below.

FIGURE 37
HVD LINES RELIABILITY INVESTMENT CATEGORY
EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Line rebuilds (miles)	$46,406,000	72
Pole top rehabilitations (miles)	$9,658,000	106
Pole replacements	$17,614,000	890
Switches (inc. SCADA additions)	$4,451,000	42
Total	**$78,129,000**	

Q. What has been the historical actual spending in the HVD Lines Reliability sub-program for the past five calendar years?

A. The Company's historical actual spending in the HVD Lines Reliability sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 9.

Q. If spending in any of the five historical years is a significant outlier, please explain why this happened.

A. In 2015, the Company experienced an increased level of demand failure activity compared to the prior year, and correspondingly had to significantly increase its year-over-year capital spending on demand failures. Consequently, in 2015, the Company had to reduce capital spending elsewhere, including in the HVD Lines Reliability sub-program. In 2017, the Company moved funding from the HVD Lines Reliability sub-program to sub-programs in LVD Reliability, particularly to address the Company's worst-performing circuits in that year.

Q. What is the basis of the Company's requested spending level in this sub-program?

A. The lines, pole tops, and poles targeted by this sub-program are among the assets that the Company needs to address to better catch up with the system deterioration discussed earlier in my testimony; therefore, the Company is proposing a large increase in investment in this sub-program. The level of expenditures requesting in this filing will allow the Company to rebuild 68 miles of HVD overhead lines and rehabilitate a further 106 miles in the 2021 test year. The lines which will be rebuilt in 2021 currently utilize either obsolete conductors, which have higher failure rates, do not have a shield wire installed to protect the line from lightning, or have access issues due to surrounding terrain. These rebuilds also contain over 265 poles which have failed to pass pole inspections and are in addition to the 890 poles listed in the pole inspection replacements investment category.

Q. What are the historical unit costs for each of the HVD Lines Reliability investment categories?

A. Historic unit costs for each category are provided in Figure 38 below:

FIGURE 38

HVD LINES RELIABILITY INVESTMENT CATEGORY UNIT COSTS

Investment Categories	***2014***	***2015***	***2016***	***2017***	***2018***
Line rebuilds	$432,400 /mile	$169,600 /mile	$706,100 /mile	$155,900 /mile	$807,500/mile
Pole top rehabilitations	n/a	$30,600/mile	$86,700/mile	$84,800/mile	$97,400/mile
Pole replacements	$17,500 /pole	$11,300/pole	$19,200/pole	$12,500/pole	$22,100/pole

Placing capital expenditures for HVD Lines Reliability into these investment categories was a new and forward-looking approach implemented by the Company for its filing in Case No. U-20134, meaning there may have been capital spending in prior years in this sub-program that does not fit into any of the three categories.

Q. Please explain any variation in unit costs over time.

A. Specific individual projects can vary widely in cost from project to project based on specific project conditions, and as a result the year-end per-unit average cost can also vary. For example, in Case No. U-20134, the Company considered 20 random work orders for pole replacements, encompassing 240 total pole replacements, and found an average cost of $18,800 per pole for that particular sample. However, considering each of those 20 work orders individually, unit costs ranged from $10,300 per pole to $29,300 per pole. Some of those work orders involved replacing poles in easier to reach locations than others or involved working in differing weather conditions. This data is shown in Exhibit A-44 (RTB-17) and illustrates the variability of pole replacement costs. Furthermore, HVD Lines Reliability projects often extend from one year into the next. In both 2014, 2016, and 2018, the Company spent significant money on line rebuild projects that were not fully completed until 2015, 2017, and 2019, respectively. Consequently, there is some money accounted as having been spent in 2014, 2016, or 2018, while the projects themselves are counted in 2015, 2017, or 2019, affecting the apparent unit costs for those years. Looking over the full five-year period, unit costs for line rebuilds have been steady.

Q. Does the Company place a greater weight on the number of incidents or on outage minutes when determining which lines to address through HVD Lines Reliability projects?

A. The Company gives slightly more weight to the HVD line sections with a higher number of incidents. Multiple incidents are a possible sign of a deteriorating system, which can be a leading indicator of future poor performance and can drive negative customer satisfaction. To ensure that the Company does not overlook an HVD line section requiring improvement by considering number of incidents alone, line sections with higher outage minutes are also considered. In the review of this sort by outage minutes, the number of incidents is included towards consideration of a potential course of action. For example, while a large thunderstorm could result in many customer outage minutes, the fact that it is a single event means the Company may not need to conduct a reliability project beyond fixing the storm damage if the line does not otherwise show deterioration. The number of incidents and the outage minutes associated with HVD line sections are two important inputs into the decision process to undertake a project, but they are not the only inputs considered. The Company also considers the configuration of an HVD line, because events on poor-performing radial lines result in more interruptions to customers compared to those on looped HVD lines. Additional inputs such as inspections, a possible field assessment, and knowledge of the system condition are applied by our engineers before a final course of action is determined.

Q. Are there any prioritized projects that make up the requested spending level in the HVD Lines Reliability sub-program?

A. The Company has identified 34 line rebuild projects for the 2021 test year, totaling 72.7 miles, which are listed in Exhibit A-42 (RTB-15), page 7, lines 1 through 34. The projects listed in Exhibit A-42 (RTB-15), page 7, lines 29 through 34, will be started in 2021 and completed in 2022. The Company has identified 20 pole top rehabilitation projects for the 2021 test year, totaling 106 miles, which are listed in Exhibit A-42 (RTB-15), page 7, lines 35 through 54. The Company developed concept approvals for many projects in this sub-program, as listed in Exhibit A-41 (RTB-14), lines 5 and 6.

Q. Are there circumstances in which the Company may reprioritize projects during the test year?

A. There are occasions in which an HVD line suddenly performs poorly, which can prompt a need to quickly react and reprioritize line rebuild or pole top rehabilitation projects. For example, in 2017, the Company saw emergent poor performance on the Waldron Line. The Company's initial reliability analysis in 2016, used to prioritize 2017 projects, had not indicated any need for action on the Waldron Line in 2017. However, in April 2017, three separate incidents in one week on the Waldron Line caused interruptions to about

5,200 customers. As a result, the Company immediately prioritized pole top rehabilitation on nine miles of the line, which was completed by October 2017.

Q. Are there any prioritized projects that make up the requested spending level in the pole replacement investment category or switches investment category of the HVD Lines Reliability sub-program?

A. The Company has not yet identified specific pole replacements or switch projects for the 2021 test year. Projects will be identified during 2020 for the test year, based on inspection results.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the HVD Lines Reliability sub-program?

A. HVD Lines Reliability projects form a critical part of the Company's glidepath for reaching 170 SAIDI minutes in 2025. Specific contributions of the HVD Lines Reliability sub-program to that glidepath were shown in Figure 2.

Line rebuilds substantially improve the performance of a line, reducing or eliminating outages and correspondingly reducing or eliminating interruptions to customers caused by that line. Figure 38 below shows how, after completing a rebuild for which line outages were a factor driving the need for the rebuild, a line section typically experiences zero or minimal line equipment-related outages. In the table, Prior Outages represent the number of line outages that occurred three to eight years before the rebuild Completion Date. Post Outages represent the number of line outages that occurred three to eight years after the Completion Date within the rebuilt line section. Customers realize the benefit of fewer outages when the Company rebuilds an HVD line section.

FIGURE 39

Impact of Line Rebuilds on Outages				
Line Description	**Completion Date**	**Prior Outages**	**Post Outages**	**Miles Targeted**
Barry – Broadmoor	2/17/2009	5	0	9.0
Dowling – Beecher	2/24/2009	4	0	21.6
Warren – Grout	3/4/2009	2	0	19.6
Monitor – Almeda	4/8/2010	1	1	22.5
Whitestone Point	6/30/2010	10	0	4.0
Parma – West	4/11/2011	2	0	10.9
Standish	7/6/2011	1	0	10.6
North Adams – North	10/10/2011	2	0	6.3
Mancelona	10/21/2011	1	0	9.0
Parma – East	11/1/2011	3	0	11.9
Nashville East	2/24/2012	3	0	11.0
Bridgeport	6/15/2012	1	0	9.5
Suttons Bay – South	10/9/2012	2	0	10.2
North Adams – Center	1/14/2013	1	0	3.8
Fremont – West	2/28/2014	2	0	4.4
Fremont – East	7/15/2014	4	0	4.6
Sanford	11/3/2014	3	0	6.3
Carson City – South	12/3/2014	7	0	6.2
Union Street	2/12/2015	2	0	4.7
Nashville Center	5/29/2015	1	0	5.5
Markey – North	5/29/2015	2	0	5.0
Carson City – North	12/1/2015	1	0	6.2
North Adams – South	12/29/2015	1	0	3.7
Peach Ridge	6/20/2016	1	0	2.7
Nashville – West	8/29/2016	2	0	5.5
	Totals	**64**	**1**	**214.7**

Similarly, in 2017 the Company performed pole top rehabilitation work on sections of the Gun Lake and Wentworth HVD lines. In the preceding four years, the lines each experienced two outages. Since the completion of the work, neither line has had any outages, demonstrating the clear benefits to customers of fewer outages when the Company rehabilitates an HVD line section.

3. <u>LVD Substations Reliability</u>

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the LVD Substations Reliability sub-program.

A. The LVD Substations Reliability sub-program ensures the long-term safe and reliable operation of LVD substations, which are the interface point between the HVD lines and LVD lines on the Company's system. Across the electric system, there is minimal LVD substation redundancy. If an LVD substation failure occurs in an urban area, depending on load levels at the time of failure, it may be possible to transfer customers to an adjacent substation through LVD line switching. If an LVD substation failure occurs in a rural area, it is unlikely that such a customer transfer could take place. Assuming no transfer ability exists, LVD substation failures create long duration outages for customers. To mitigate this risk, the LVD Substation Reliability sub-program invests in several categories, including: (i) new or rebuilt substations; (ii) new mobile substations; (iii) animal mitigation; (iv) transformer replacements; and (v) regulator replacements.

Q. Please provide further information on the animal mitigation investment category.

A. The purpose of each animal mitigation project is to keep animals, such as squirrels and raccoons, out of the substation and to insulate equipment to extend touch potential should an animal get into a substation, with specific measures chosen based on substation characteristics. Common animal mitigation measures include: (i) 1-inch mesh fence (squirrels can squeeze through larger mesh); (ii) concrete gate foundations (minimizes gaps and frost heave that create gaps over time); (iii) polycarbonate panels (3-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.

Q. Are there specific measures incorporated into animal mitigation work to reduce the potential for animals to enter the substation from above?

A. Yes. Line discs and pole wraps are incorporated into the current LVD substation animal mitigation standard and utilized where applicable, to reduce the potential for land animals to enter the substation from above. 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, but there have been no bird-caused incidents at the substations in this list of 2021 projects.

Q. How does the Company identify needed investments in the LVD Substations Reliability sub-program?

A. The Company uses several inputs and analyses to determine how to best target LVD Substations Reliability issues. These inputs help to identify specific areas to target investments based on probability of future issues and help to prioritize projects that will deliver the greatest reliability improvements based on SAIDI and SAIFI. These inputs include:

- **LVD Lines engineers –** Analyze historical outage trends on the LVD lines system to identify areas of greatest reliability concern based on total number of outages, trends in reliability performance, and potential reliability impact;

- **Input from field operations and other departments** – Inform substation planning engineers on operational concerns and system constraints that may trigger necessary projects, such as working clearance constraints;
- **Animal intrusion data** – Animal mitigation projects are implemented to mitigate recurrence of animal-caused substation outages;
- **Equipment trend data** – Planned replacement of substation equipment may be triggered with trend data that indicates degrading equipment condition, but has not reached a concern of imminent failure; and
- **Mobile substation planning** – Includes assessing and maintaining the Company's mobile substation fleet based on historical project usage and the purchase of new mobile substations to replace those which have become uneconomical to repair.

Q. Does the Company consider non-wires alternatives in the LVD Substations Reliability sub-program?

A. At this time, the Company does not believe that non-wires alternatives are mature enough to adequately address the reliability issues that are targeted by this sub-program. In order to be considered as reliability solutions, non-wires alternatives need to have well-established costs, deployment schedules, and reliability parameters, meaning the Company must be confident that the solution will perform as intended when called upon. Non-wires alternatives that are currently readily available do not yet meet these criteria for LVD Substations Reliability projects. The Company has been studying how non-wires alternatives can be considered as capacity solutions, which I will discuss in the LVD Substations Capacity section of my direct testimony.

Q. What is the Company's projected 2021 test year spending level, 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 $15,502,000 as shown in Exhibit A-31 (RTB-4), line 3, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the five investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 40 below.

FIGURE 40
LVD SUBSTATION RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	**Capital**	**# of Units**
New or rebuilt substations	$5,140,000	3
Mobile substations	$3,360,000	1
Animal mitigation	$4,002,000	40
Transformer replacements	$2,000,000	3
Regulator replacements	$1,000,000	34
Total	**$15,502,000**	

Note: The Company plans to *complete* three new or rebuilt substations projects in 2021 but will begin work on a fourth project to be completed in 2022. 2021 test year spending for the fourth project is included in Figure 40.

Q. What has been the historical actual spending in the LVD Substations Reliability sub-program for the past five calendar years?

A. The Company's historical actual spending in the LVD Substations Reliability sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 10.

Q. If spending in any of the five historical years is a significant outlier, please explain why this happened.

A. Spending in this sub-program increased in 2016, as the Company built one new substation, rebuilt one existing substation, and made a large investment in a mobile substation. Spending increased further in 2017, as the Company invested in additional mobile substations. After reverting to the average in 2018, spending increased again in 2019 as the Company invested in four rebuilds of existing substations. The investment in mobile substations has been necessary as aging mobile substations have neared the end of their lifespans; an adequate mobile substation fleet is critical for completing other projects in the LVD Substations Reliability and LVD Substations Rehabilitation sub-programs. The investment in substation rebuilds has been necessary, primarily to address working clearance code violations

Q. What is the basis for the Company's requested spending level in this sub-program?

A. The Company's actual spending in this sub-program has been increasing, so it is reasonable that projected spending for the 2021 test year is higher than historical levels. As discussed earlier in my direct testimony, the Company is increasing its spending in key Reliability sub-programs in order to drive reliability improvements on the system. The level of spending requested in this filing will enable the Company to (i) rebuild three LVD substations, and start a fourth rebuild project; (ii) purchase one new mobile substation; (iii) install animal mitigation measures at 40 substations; (iv) replace three substation transformers; and (v) replace 34 substation regulators.

Q. Please list any prioritized projects that make up the requested spending level in the LVD Substations Reliability sub-program for the 2021 test year.

A. The following new or rebuilt substations projects have been identified for the 2021 test year:

- Rebuild of the Mt. Morris substation - $1,500,000;
- Rebuild of the Tawas substation - $1,500,000;
- Rebuild of the Thornton substation - $1,500,000; and
- Rebuild of the Maple City substation - $640,000 (2021 spending only; project continues into 2022).

These four new or rebuilt substations for the 2021 test year are listed in Exhibit A-42 (RTB-15), page 8, lines 6 through 9. In the 2021 test year, the Company will invest $3,360,000 in Mobile Substation #24. This mobile substation for the 2021 test year is listed in Exhibit A-42 (RTB-15), page 8, line 10. The Company has identified 37 animal mitigation projects for the 2021 test year, as listed in Exhibit A-42 (RTB-15), page 8, lines 11 through 47. The Company has identified 34 regulators for replacement, at 12 sites, for the 2021 test year, as listed in Exhibit A-42 (RTB-15), page 9, lines 1 through 12. The following transformer replacement projects have been identified for the 2021 test year:

- Transformer replacement project at Leland substation - $500,000;
- Transformer replacement project at Lambertville substation - $750,000; and
- Transformer replacement project at Schuss Mountain substation - $750,000.

The transformer replacement projects for the 2021 test year are listed in Exhibit A-42 (RTB-15), page 9, lines 13 through 15. The Company developed concept approvals for many projects in this sub-program, as listed in Exhibit A-41 (RTB-14), lines 7 through 9.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Substations Reliability sub-program?

A. Projected test year spending provides for the level of investments necessary in LVD substation reliability to address obsolete, poor performing assets and equipment to support the Company's reliability objectives. In particular, since 2012, when the Company increased animal mitigation installations at LVD substations, approximately 96% of substations equipped with the current substation animal mitigation standard have experienced no animal-caused outages since the installation was complete.

4. <u>HVD Substations Reliability</u>

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the HVD Substations Reliability sub-program.

A. The HVD Substations Reliability sub-program ensures the long-term safe and reliable operation of HVD substations, with investments to replace existing substation equipment. This sub-program consists of four investment categories: (i) circuit breaker and circuit switcher replacements; (ii) transformer bushing replacements; (iii) switch replacements; and (iv) other targeted replacement programs for specific equipment, such as potential transformer replacements and substation lightning arresters.

Q. What work is included in the circuit breaker and switcher replacement investment category?

A. Circuit breakers and circuit switchers are key and integral components of the HVD protection system. The purpose of these devices is to minimize customer outage impact and mitigate equipment damage when the system experiences and clears an electrical fault. The units replaced are generally 1950s and 1960s vintage oil breakers and their performance coupled with the increasingly limited availability of parts are the two key inputs driving these replacements.

Q. What work is included in the transformer bushing replacement investment category?

A. Transformer bushings replacements include bushing types with high failure rates, such as General Electric ("GE") Type U, and bushings with observed degradation. The GE Type U bushings are known industry wide to have higher failure rates than average bushing failure rates. The Company has been systematically replacing Type U bushings for several years, based on customer impact and consideration of other scheduled work in the substation to maximize workforce efficiency and utilization.

Q. What work is included in the switch replacement investment category?

A. The Company replaces obsolete switches in conjunction with other substation work, in order to maximize efficiency and workforce utilization.

Q. Are major HVD substation components replaced simply due to age?

A. No. The Company does not have a systematic program to replace major substation components solely based on age. Instead, the Company uses multiple inputs and analytic processes to aggregate numerous data sources to best target reliability issues. These help to identify specific areas to target investments based on probability of future issues, and to prioritize projects that will deliver the greatest reliability improvements.

Q. Please describe these inputs and processes in more detail.

A. The key inputs used in our project planning process are test data, analytic algorithms, reliability improvement initiatives, and equipment trend data. The test data reviewed includes transformer and battery electrical test data and circuit breaker operational testing and operation history. The data from oil dissolved gas tests of transformers, Load Tap Changers , circuit breakers, and voltage regulators are reviewed and also set to subscription Industry Standard Analysis Algorithms.

The Criticality, Health, and Risk ("CHR") analytic algorithm has been developed for specific equipment groups. The Company developed CHR in collaboration with Digital Inspections experts. This algorithm has been customized for our equipment based on equipment analysis experience coupled with industry parameters. Where applied, the algorithm will produce a risk analysis based on an applied criticality (to the system) input and a health value developed using test results. This can be a useful component in the prioritization process for equipment replacement projects. Based on these results, the Reliability Engineers may then initiate a substation equipment replacement project. Additionally, collaboration and input from field organizations and other departments provides substation Reliability Engineers with information regarding operational concerns that can initiate individual substation equipment replacement projects.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the HVD Substations Reliability sub-program?

A. The Company is projecting HVD Substations Reliability capital expenditures of $5,223,000 as shown in Exhibit A-31 (RTB-4), line 4, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the four investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 41 below.

FIGURE 37
HVD SUBSTATION RELIABILITY INVESTMENT CATEGORY
EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Circuit breaker/switcher replacements	$3,000,000	20
Transformer bushing replacements	$1,200,000	12
Switch replacements	$600,000	17
Other	$423,000	12
Total	**$5,223,000**	

Q. What has been the historical actual spending in the HVD Substations Reliability sub-program for the past five calendar years?

A. The Company's historical actual spending in the HVD Substations Reliability sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 11.

Q. What is the basis of the Company's requested spending level in this sub-program?

A. The Company's actual spending in this sub-program has been on an upward trend, so it is reasonable that projected spending for the 2021 test year is above the spending levels reached in the past five years. As discussed earlier in my direct testimony, the Company is increasing its spending in key Reliability sub-programs to drive reliability improvements on the system. The level of spending requested in this filing will enable the Company to (i) complete 20 circuit breaker and switcher replacements; (ii) complete 12 transformer bushing replacements; (iii) complete 17 switch replacements; and (iv) complete 12 other projects (potential and station power transformer replacements).

Q. Are there any prioritized projects that make up the requested spending level in the HVD Substations Reliability sub-program for the 2021 test year?

A. The Company has identified 12 transformer bushing replacement projects for 2021 as listed in Exhibit A-42 (RTB-15), page 9, lines 18 through 29. The Company has identified 12 switches for replacement at nine substation locations for 2021, as listed in Exhibit A-42 (RTB-15), page 9, lines 30 through 38. The Company has identified 20 circuit breaker and switcher replacements at six substation locations for replacement in 2021, as listed in Exhibit A-42 (RTB-15), page 9, lines 39 through 44. The Company has identified 12 projects at four substation locations for 2021, as listed in Exhibit A-42 (RTB-15), page 9, lines 45 through 48. At the Brown Paper and Oceana substations, the Company will replace one station power transformer at each location. In the Trowbridge, Merson, and Broadmoor substation projects, the Company will replace three and seven potential transformers, respectively. These potential transformer and station power transformers are all replacements for Maloney transformers that have been identified as prone to failure. The Company has developed concept approvals for projects in this sub-program, as listed in Exhibit A-41 (RTB-14), line 10.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the HVD Substations Reliability sub-program?

A. HVD substations are typically designed with some redundancy, such that the first contingency should not result in any interruptions to customers, which limits the SAIDI impact of any single failure of an HVD substation component (as shown in Figure 16 earlier in my direct testimony, HVD substations contribute only a small amount toward system SAIDI). However, because HVD substations are typically the interface point between the transmission provider and Consumers Energy, they represent particularly critical locations on the electric distribution system, as a second contingency could cause interruptions to many customers. For radial configurations where customers are fed by a single line, the failure of any component can cause outages for all customers on a line, making the devices contained in such substations critical to serving customers. Therefore, preventative reliability work at HVD substations, to keep this redundancy in place, is vital to overall grid reliability.

5. Grid Modernization

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the Grid Modernization sub-program.

A. The Company's overall Grid Modernization strategy, which covers multiple years, was discussed in detail earlier in my direct testimony. In the 2021 test year, the Company will make investments in two broad groups of Grid Modernization projects: (i) automation and (ii) advanced technologies.

Q. What projects are included in the automation group?

A. The automation group includes four investment categories: DSCADA and SCADA, ATR loops, line sensors, and regulator controllers.

Q. What is DSCADA?

A. DSCADA is the key component of LVD substation automation, allowing the Company to open and close substation devices remotely without having to send a human operator. When DSCADA is installed at a substation, it includes a Remote Terminal Unit ("RTU"), a local device that facilitates communications with substation devices and remote software systems and captures over 300 data points within the substation and uses a cellular modem to transmit the data to the Company's operators. The enhanced visibility into substations and the remote-control capabilities together allow the Company to address outages more quickly and effectively. By enhancing visibility, DSCADA allows the Company's distribution planners to perform more accurate load flow studies, since DSCADA provides access to real-time circuit data; load flow studies can therefore be dynamic based on time of year or day. The remote-control aspects of DSCADA are crucial in enabling CVR, FLISR, and VVO capabilities, and in making ATR loops operable.

Q. What is FLISR?

A. FLISR allows the Company to quickly and automatically restore power to as many customers as possible, without requiring intervention by Company operators or crews. FLISR can detect a fault on the system and then automatically operate switches and reclosers to isolate the fault and transfer as many customers as possible to being served by an alternate substation or circuit until the fault can be addressed. This reduces outage durations for customers and reduces outage costs for the Company by reducing demands on service crews.

Q. What is VVO?

A. VVO enables coordinated control of voltage regulators and switched capacitor banks to reduce system losses and eliminate waste, using regulator controllers, capacitors, DSCADA, and ADMS. Without this capability, the Company must maintain voltage at the substation near the upper threshold of MPSC standards in order to ensure that voltage is delivered at a high enough level to customers once line losses are accounted for. By replacing regulators and capacitors, the Company can improve its voltage performance by reducing line losses. The major benefit of VVO is that it reduces line losses, enabling CVR, which provides a reduction in energy consumption. CVR is discussed in more detail in the Capacity program section of my direct testimony.

Q. What are voltage regulators and controllers?

A. Voltage regulators are essentially a tap changing transformer utilized to increase or decrease voltage on the primary distribution system based on changing load conditions. Controllers allow sophisticated remote control of the regulators. Voltage regulators contain internal windings and mechanisms to adjust the voltage by up to 10% in either direction, are located on the pole top, and are connected to regulator controllers at the pole base. The Company is in the process of replacing the existing devices with modernized voltage regulator controllers that will enable two-way communication between the controller at the pole base with the DSCADA system. With remote monitoring and control, the Company can ensure that it is providing customers with the correct voltage and improve system efficiency. Modernized regulators and controllers are critical in enabling VVO and CVR. Voltage control is further enhanced by remote controlled capacitors, which provide reactive power to the distribution system, correcting power factors by compensating for reactive losses and thereby increasing voltage. These capacitors are also controlled by cellular modems at the pole base.

Q. What are ATR loops?

A. ATRs are a key component for enabling distribution automation loops on the system. This technology is installed in sets on the system between two LVD feeders creating an automation loop, with three to five ATR devices being installed on a typical LVD circuit. ATRs transfer load automatically in the event of an outage, reducing customer outages and improving system reliability by isolating a faulted section of a circuit. When an ATR operates during a distribution event, the fault on the distribution system is automatically isolated and the rest of the customers are automatically restored within 90 seconds. ATR deployment is coordinated with DSCADA deployment, with the two classes of device being integrated by ADMS, all of which is critical in enabling FLISR.

Q. What are line sensors?

A. Line sensors are devices that, by monitoring voltage and current, can detect faults and determine the faulted section and probable location of a fault, making them critical in enabling FLISR. Line sensors also provide information such as circuit loading, circuit balance fault current data, momentary outages, permanent faults, line disturbances, and high current alarms. In addition to operational capabilities, line sensors can be used to improve the entire LVD Planning process, by allowing more accurate load flow modeling. Not only can sensors improve the model for the circuits they are installed on, but the analysis performed using the data from line sensors can be used to improve the Company's load model statewide. This more accurate and near real-time load information can be used to improve the load transfer process both for planned and unscheduled outages. This will reduce the duration of the manual load transfer writing process and improve the accuracy of the modeled transfers. Data is transmitted to Company operators using the cellular phone network.

Q. What projects are included in the advanced technologies group?

A. The advanced technologies group includes four investment categories: ADMS, Distributed Energy Resource Management System ("DERMS"), grid operational analytics, and a grid technologies project.

Q. Does the Grid Modernization sub-program support the Company's SAIDI glidepath?

A. Yes. Specific contributions to the glidepath from the Grid Modernization sub-program are identified in Figure 2 and Figure 3 earlier in my direct testimony.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the Grid Modernization sub-program?

A. The Company is projecting Grid Modernization capital expenditures of $69,604,000. The automation group component of this spending is $60,421,000, as shown in Exhibit A-31 (RTB-4), line 5, column (f). The advanced technologies component, including ADMS, DERMS, and grid operational analytics, is $7,833,000, as shown in Exhibit A-31 (RTB-4), line 6, column (f). The grid technologies project is $1,350,000, as shown in Exhibit A-35 (RTB-8), line 7, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the eight investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 42 below.

FIGURE 38
GRID MODERNIZATION INVESTMENT CATEGORY
EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Automation		
DSCADA & SCADA	$21,542,000	118*
ATR loops	$21,258,000	39
Line sensors	$4,544,000	100
Regulator Controllers	$13,077,000	393
Advanced Tech.		
ADMS	$5,900,000	n/a
DERMS	$1,184,000	n/a
Grid operational analytics	$748,000	n/a
Grid technologies	$1,350,000	n/a
Total	**$69,604,000**	

The advanced technology investment categories are not delineated on a unit basis. In the DSCADA and SCADA investment category, the Company has identified 118 DSCADA locations, and will also conduct a limited amount of work to maintain SCADA, through the capital addition and/or replacement of relays, RTUs, controllers, communication assemblies, and servers.

Q. What has been the historical actual spending in the Grid Modernization sub-program for the past five calendar years?

A. The Company's historical actual spending in the Grid Modernization sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), lines 16, 17, and 54.

Q. What is the basis for the Company's spending request in this sub-program?

A. As I described earlier in my direct testimony, the Company's Grid Modernization strategy is based on a layered multi-year investment approach that takes place over several years to develop several interdependent technologies and capabilities, and the Company correspondingly increased its Grid Modernization spending each year from 2014 through 2019. Continuing this trend, the Company's projected 2021 spending is higher than historical levels. The level of spending requested in this filing will enable the Company, in 2021, to (i) install DSCADA at up to 118 sites; (ii) install up to 39 ATR loops; (iii) complete up to 100 line sensor projects; and iv) install up to 393 regulator controllers. This spending will also enable investments in ADMS, DERMS, grid operational analytics, and the grid technologies project.

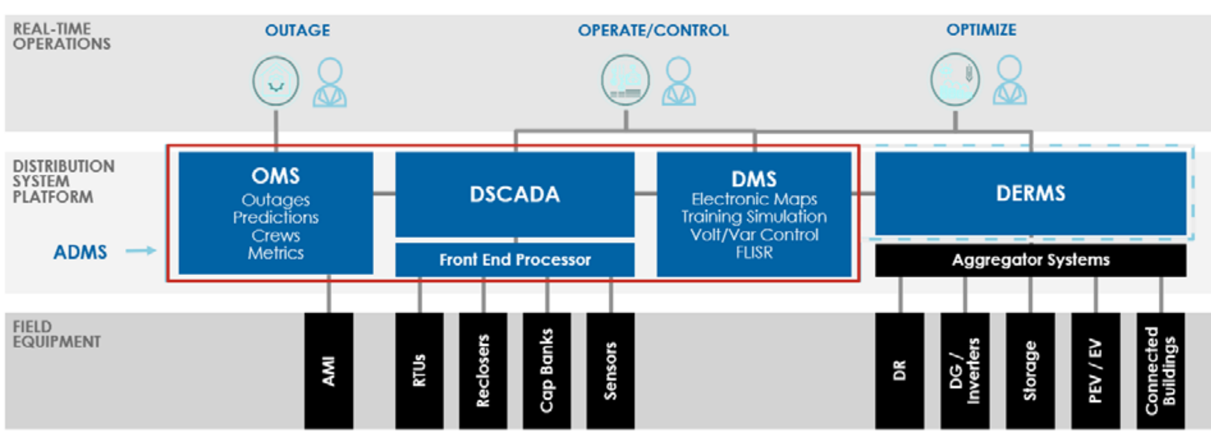
Q. Are there any identified automation projects for the 2021 test year?

A. The Company has identified sites for DSCADA, ATR loops, line sensors, and regulator controllers, as listed in Exhibit A-42 (RTB-15), pages 10 through 21. As the Company completes its designs for these sites, the Company will identify clear site-by-site costs and resource needs and will build a detailed workplan using these sites. The Company developed a concept approval for ATR loops, as shown in Exhibit A-41 (RTB-14), line 11.

Q. Please further explain ADMS.

A. ADMS is a software platform that integrates components of Grid Modernization, incorporating data from the different devices on the distribution system to increase automation and improve real-time outage management. It is critical to enabling all the Grid Modernization capabilities, including DER integration, laying the foundation for DERMS. ADMS combines a new Distribution Management System ("DMS") and Outage Management System ("OMS") into a single platform, replacing the Company's existing OMS, and integrating these components with DSCADA. This is illustrated in Figure 43 below. ADMS also integrates the Company's GIS mapping to provide operators and dispatchers with an accurate and realistic view of the distribution system, phasing out the need for traditional paper-based single line system diagrams and maps for these users. The Company began its deployment of ADMS in 2019, the beginning of an approximately two-and-a-half-year process that is planned to conclude in the first quarter of 2021.

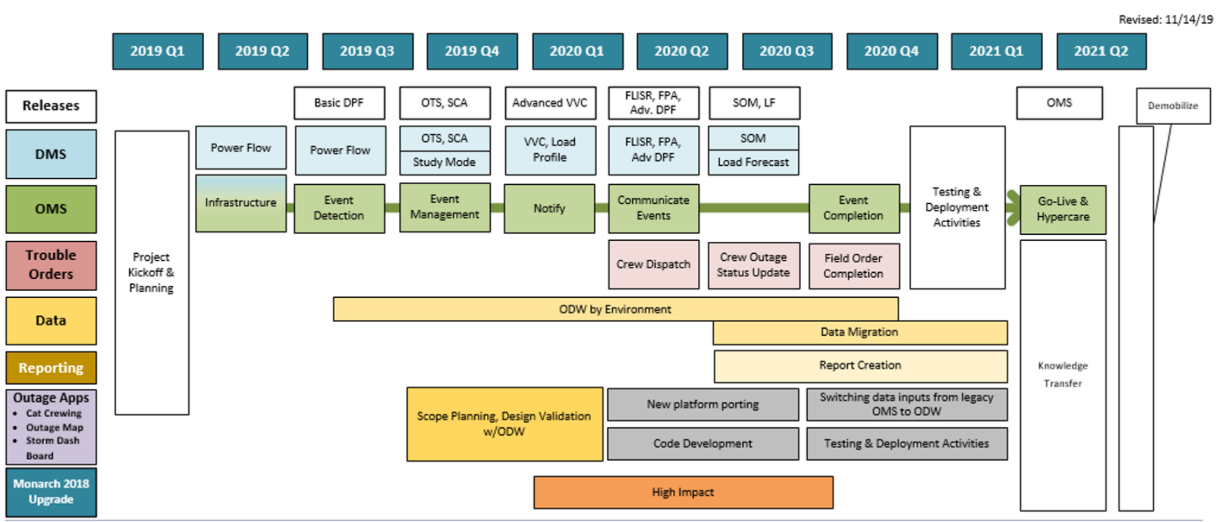
Figure 39
Illustration of ADMS



Q. What are the deliverables during this deployment process?

A. The process will deliver releases of ADMS functionality periodically during the deployment timeframe according to the project release schedule, as illustrated in Figure 44 below.

FIGURE 40
ADMS DEPLOYMENT ILLUSTRATION



Q. Please define and describe each of the releases.

A. The releases consist of the following:

- **Basic Distribution Power Flow ("DPF") –** This functionality is a power flow application which performs a full, unbalanced three-phase calculation of the voltage, current, and power flow in a low voltage distribution network based on current topology, telemetered data, and estimated load values. DPF is foundational to the other ADMS modules such as FLISR and Switch Order Management ("SOM");

- **Operator Training Simulator ("OTS") & Short Circuit Analysis ("SCA")** – The OTS is a realistic operations training environment which simulates real-time scenarios and events on the low voltage distribution system, providing an enhanced training experience for the Distribution Control Center ("DCC") operators and the Distribution Operations Engineering team. SCA will be utilized by advanced applications to calculate the effects of a fault and improve the operational response on the LVD system. This will help identify and isolate the fault for more efficient service restoration;

- **Advanced Volt-Var Control ("VVC") –** This release builds upon the existing VVC capability. Advanced VVC allows monitoring and managing of distribution system voltage levels at capacitor bank and regulator devices. Voltage violations at any device will be verified with either telemetered (using DSCADA) or calculated (using Distribution Power Flow ("DPF")) values. These enhancements will help conserve voltage and provide a more efficient way to resolve voltage and VAR issues;

- **FLISR, Fault Protection Analysis ("FPA") & DPF –** FLISR was described earlier in my direct testimony. FPA will help identify potential over-current and under-current violations on the LVD system. Advanced DPF will build on the Basic DPF functionality, by implementation of load profiles that classify customer electric usage. This will allow users to simulate load transfers and respond more accurately to high loading events;

- **SOM & Load Forecasting –** SOM is a web-based application that provides tools needed to process switching requests, design effective switching strategies, verify actions before the order is dispatched, and safely execute switching orders in coordination with field personnel. Load Forecasting is a simple and reliably short-term load forecasting tool. This is the final DMS release of functionality to be delivered by the ADMS project; and

- **OMS –** This release is the replacement of the existing OMS with the new integrated OMS, which includes enhanced capabilities such as improved visualization, work prioritization, and the ability to segment work headquarters to improve span of control which will enable dispatchers to safely and more effectively manage work crews during restoration work.

Q. What are the primary benefits of ADMS?

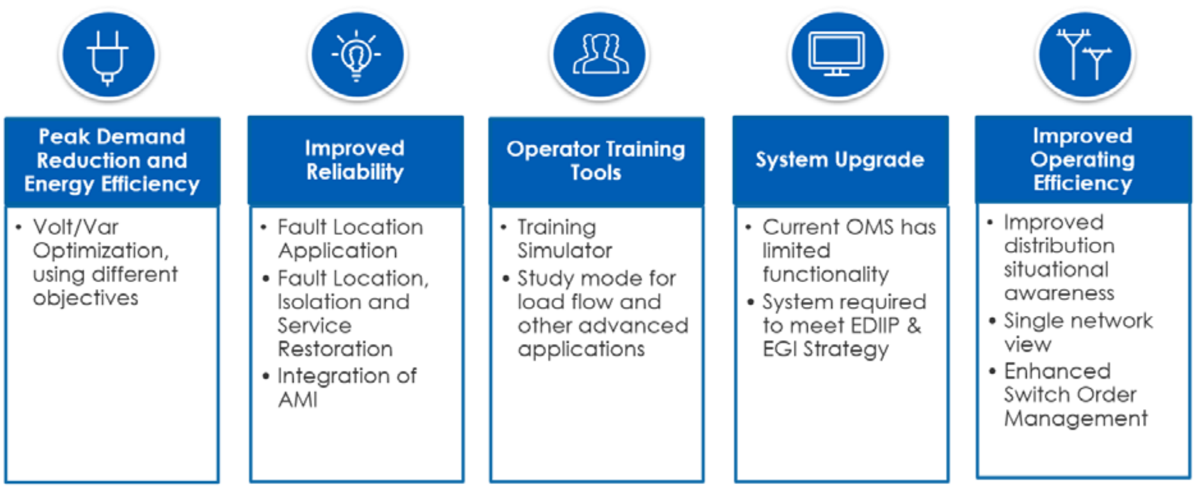
A. ADMS will enable the Company to perform load transfer studies much more quickly in the future. Currently, it takes about four hours to complete such a study manually. In the future, with the automated capabilities of ADMS, a load transfer study will be performed in less than 30 minutes. This will deliver benefits to customers by reducing outage times through load transfers. The Company predicts that there will be a reduction of 10 minutes of SAIDI and $226,000,000 in net benefits to customers through this load transfer capability.

ADMS will provide system automation to enable the Grid Modernization capabilities that the Company is developing; ADMS will not only enable capabilities like

FLISR, VVO, CVR, and DER integration, but also provides a platform upon which other as-yet unidentified capabilities can be developed in the future.

Furthermore, ADMS will improve situation awareness for dispatchers, improving safety and effectiveness; currently, a dispatcher must look at two different computer monitors with two different software applications to see the distribution system and crew locations. In the future with ADMS, the crew locations will be shown on the same view as distribution outages and hazards which will improve dispatching. These further benefits of ADMS are summarized in Figure 45 below.

FIGURE 415
SUMMARY OF BENEFITS OF ADMS



Q. What work is the Company planning to complete on ADMS in the 2021 test year?

A. Much of the work on the Company's ADMS project will have been done in years prior to 2021, so the Company's capital spending in the 2021 test year will be used to complete the ADMS project, with a targeted completion at the end of the first quarter of the year. Capital spending in the 2021 test year will also cover final testing and go-live activities.

Q. What is DERMS?

A. DERMS is an advanced software platform including, but not limited to, specific functions to forecast, monitor, control, and coordinate DERs on the electric grid. The DERMS application will provide several key functions including aggregation, translation, simplification, and optimization across a wide variety DERs. DERMS will optimize DER performance at multiple levels based on multiple requirements including local, regional, and system-wide applications.

Q. How is the Company planning to implement DERMS?

A. The Company will deploy DERMS functionality to optimize and control a limited number of DERs and address potential local operational challenges associated with DER penetration at the circuit and/or substation level. This will allow the Company to initially learn by monitoring and controlling DERs on a small subset of circuits and/or substations to understand the unique challenges associated with managing DERs in front of the meter. As DERMS mature, the Company will follow small-scale DERMS deployment with an Enterprise DERMS solution integrated with ADMS.

Q. What work is the Company planning to complete on DERMS in the 2021 test year?

A. The Company plans on first deploying a small focused DERMS to control a limited number of DERs and address potential local operational challenges associated with DER penetration on LVD circuits. This will allow the Company to evaluate DERMS functionality through monitoring and controlling the DERs on a small subset of circuits. Additional circuits and DERs will be introduced in 2021 to allow for further testing of additional use cases and communication interfaces. The entire first phase of DERMS is estimated to take 24 to 36 months, beginning in 2020 and ending in 2022, and cost approximately $3,000,000. Cost components include planning and procurement, internal and external resources to implement the system, hardware and software costs, and maintenance of the system.

Q. What work is the Company planning to complete in grid operational analytics in the 2021 test year?

A. Grid operational analytics provides a phased approach to enable new analytics with ongoing incremental improvements. In 2018 and 2019, the Company established a scalable data management architecture platform to enable analytics sprints that were outlined in the EDIIP. Many of these initial EDIIP analytics are based on evaluating smart meter data on an individual basis or with respect to discrete events. For example, an initial analytic for mis-phasing was based on evaluating meters reporting a power outage. Although this provides a means to identify meters that might have incorrect phasing data, it requires an interruption of service to perform the analysis. In the 2021 test year, the Company will build upon that foundation and invest in additional analytics capabilities using electric network connectivity data and DSCADA data to be able to evaluate mis-phasing without having to wait for an outage event, moving the analytic from being a reactive analysis to a proactive analysis. It will also enable the Company to run the analytics on a system-wide basis, not just for those locations that have experienced an interruption of service. This investment will also enable completion of more advanced analytics for loading, power quality, and outage analytics.

Q. Please explain the grid technologies project.

A. The Company is contracting with a third party to develop an application to improve the Company's ability to leverage its GIS data. Currently, when Company employees are in the field to do system assessments, to evaluate site conditions for work, and to conduct preliminary design work, they capture images using various devices. Those images then reside on individual employee computers, unavailable to other employees in a seamless way, and eventually much of the imaged information is lost. The purpose of this project is to create a way to seamlessly integrate these images of system assets into the Company's GIS data.

Q. What is the primary benefit of this project?

A. The primary benefit is to enhance the prioritization of issues to address during system assessment by capturing images of potential problem areas, integrating the image into the Company's GIS data, and ensuring that they receive the correct priority level. When the image is associated with an asset, the Company can determine potential impact to customers, and will be better positioned to address the highest-risk issues as soon as possible.

Q. Will this project improve reliability solely through better prioritization?

A. No. This project will also help the Company increase system assessment frequency. Currently, the Company assesses its LVD system once every six years, but as infrastructure ages, the Company will need to increase this frequency to once every three years. This program will streamline that process and also ensure that GIS data is periodically validated.

Q. What other benefits will this project provide?

A. This project will help ensure that crews have the right equipment and material to perform their work before they arrive in the field. There are several examples of information that, when stored with an image in the Company's GIS data, can improve the efficiency of repairs and other field work. It could indicate a high traffic area where traffic control would be required to complete a job. It could indicate muddy terrain, requiring specialized vehicles to complete a job. It could indicate that a pole is in a customer backyard where there is an aggressive dog, meaning precautions need to be taken.

Additionally, images that are centrally stored and associated with assets through GIS data can be provided to designers, who can then determine what, if any, engineering is needed for a project without making a field visit. Schedulers will be better able to group issues that are close to one another, minimizing crew travel time. The Company will be better able to evaluate defect trends and optimize assessment frequency. Images captured before and after a job can be compared to validate the work.

Q. What work is the Company planning to complete in the 2021 test year for this grid technologies project?

A. Spending in the 2021 test year will bring this project to operational status. Spending in subsequent years will relate only to ongoing operation of the new technology.

6. System Protection

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the System Protection sub-program.

A. The System Protection sub-program replaces obsolete, high-maintenance electromechanical ("EM") relays and sequence of events recorders with digital devices and adds new digital devices that have fault monitoring capabilities to improve reliability and offset future O&M costs. This sub-program targets high maintenance relays that are reaching end of life and supports the replacement of relays due to North American Electric Reliability Corporation requirements.

Q. What is the purpose of these components of the HVD protective system?

A. The purpose of a protective system is to de-energize, as quickly as possible, the minimum amount of the electric network that has experienced an electrical fault in order to isolate the fault and mitigate damage to other equipment. The failure of a protective relay to respond correctly can lead to extended breadth and length of outages experienced by customers, increased likelihood of major equipment or conductor damage, and possible unsafe conditions for employees or the public.

Q. What is the present state of the Company's HVD protective system?

A. Approximately 16% of the protective relay population is older than the designated design life; this increases to 31% for the population of EM relays. Experience has shown that as relays age they are found to be out of tolerance more often; therefore, more frequent field testing and calibration is required in order to assure proper performance. Digital relays are tested less often than EM relays reducing O&M test expenses. Relays typically have an increased failure risk as they age. One particular historically popular EM relay requires maintenance twice as often as other EM relays in order to keep them within their setting tolerance. This model of relay is targeted for replacement to reduce O&M expenses as well as the risk of failure. Over the past three years, relays contributed to approximately 37% of the failures of an HVD protective system to clear a fault and restore un-faulted HVD equipment correctly.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the System Protection sub-program?

A. The Company is projecting System Protection capital expenditures of $2,344,000, as shown in Exhibit A-31 (RTB-4), line 8, column (f).

Q. What has been the historical actual spending in the System Protection sub-program for the past five calendar years?

A. The Company's historical actual spending in the System Protection sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 12.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Beginning in 2017, unit costs for completing relay replacements began to increase. A major driver of this increase was changes in relay panel layouts, which was required to comply with stricter National Electrical Safety Code ("NESC") working space standards. As a result, projects at older locations include the need to install new and larger control houses; modifications to station power and DC battery supplies; and relocation of existing equipment, including the cost of trenching control cables between facilities.

Q. What is the basis for the Company's projected test year spending level in the System Protection sub-program?

A. The Company's projected System Protection investment in 2021 is in line with historical actual spending in this sub-program, slightly lower than spending levels typically reached in prior years. The level of spending requested in this filing will enable to Company to continue replacing line exit relays that are reaching end of life, with 35 replacements at five locations planned for the test year.

Q. What are the historical unit costs for the System Protection sub-program?

A. Historical unit costs are provided in Figure 46 below; note that some projects span multiple years:

FIGURE 426
SYSTEM PROECTION UNIT COSTS

Investment Categories	*2014*	*2015*	*2016*	*2017*	*2018*
Locations	16	7	6	6	5
Total Relay Replacements	33	19	17	29	16
Cost per Location	$148,300	$271,300	$261,500	$707,300	$600,000
Cost per Relay Replacement	$71,900	$99,900	$92,300	$146,300	$187,500

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. Relay replacement unit costs began increasing in 2017, as described above. 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. Spreading spending over multiple years misaligns the numerator (cost) and denominator (unit) when calculating unit costs, making unit costs less consistent from year to year.

Q. Please list any prioritized projects that make up the requested spending level in the System Protection sub-program for the 2021 test year.

A. The Company is planning to replace 35 relay packages across the Bingham, Lake Shore, Dort, Gleaner, and Beveridge substations. The project at the Beveridge substation will carry into 2022. These projects for the 2021 test year are listed in Exhibit A-42 (RTB-15), page 22, lines 1 through 5. The Company developed concept approvals for these projects, as listed in Exhibit A-41 (RTB-14), line 12.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the System Protection sub-program?

A. The projected test year amount provides for the level of investments necessary in System Projection to address obsolete, poor performing relays to ensure proper operability of the HVD network and minimize the risk of lengthy outages to customers. Also, the investments will minimize the risk of major equipment or conductor damage, and possible unsafe conditions for employees or the public that can be associated with HVD outages. Additionally, new digital relays contain oscillographic recording functions that allow for evaluation of system conditions in real time, allowing engineers to remotely interrogate the system to locate faults more quickly and with more precision. This allows repair crews to address problems and restore customers more quickly, reducing CAIDI. Furthermore, experience has shown that digital relays can be tested once every five years instead of once every four years for EM relays. The time spent to test and calibrate digital relays is 50% less than a comparable EM relay. One HVD relay project typically replaces six EM relays with two new digital relays. Considering these reductions, it is estimated that a modern digital relay package requires 87% less O&M expense on average to maintain than a comparable EM unit.

7. <u>LVD Repetitive Outages</u>

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the LVD Repetitive Outages sub-program.

A. The LVD Repetitive Outages sub-program addresses areas of the distribution system that consistently experience recurring customer interruptions, measured by the CEMI index, inclusive of MEDs. CEMI measures how many customers have experienced more than a given number of interruptions in a particular year. For LVD Repetitive Outages, the Company considers CEMI-5+, or the percentage of customers who experience five or more interruptions annually. Investments in this program address issues of frequent interruptions by targeting specific zones for improvements. Specific projects are not known far in advance for this sub-program. The Company will identify areas on the system to target later in 2020 and continuing into 2021, developing solutions for those areas following the process described below.

Q. What kinds of improvements are made for these targeted zones?

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., to fuses, switches, reclosers) –** This prevents or minimizes damage to lines and equipment caused by system faults, 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;

- **Upgrading lightning protection to meet standard**s **–** For example, the Company installs lightning arrestors (otherwise known as surge arrestors) every 1,300 feet as a Company standard; and

- **Replacing deteriorated or non-standard equipment –** Items identified for replacement include poles, cross-arms, pins and insulators, lightning arrestors, non-standard equipment, and cutouts.

Q. How does the Company identify issues that would require an LVD Repetitive Outages project?

A. RAE data, as discussed in detail 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 planners. 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 looking at areas where customers are likely to experience five or more interruptions annually, the Company can develop projects that have the greatest reliability benefit for the highest number of customers first.

Q. Please describe the RAE zonal analysis report further.

A. Figure 47 below shows a segment from the monthly zonal summary report. In this example, several customers had experienced 10 or more interruptions on the circuit. There were two zones that contributed to a majority of these interruptions. Based on this information, an LVD circuit planner would look at the detailed information, an example of which is shown in Figure 48, to identify appropriate measures to reduce future interruptions.

FIGURE 437
SCREENSHOT EXAMPLE OF ZONAL ANALYSIS SUMMARY REPORT

Protective Device 1	Protective Device 2	Protective Device 3	Protective Device 4	Protective Device 5	Protective Device 6	Total Customer Interruptions
1335-04-SUB[0]	1335-04-0164[3]	1335-04-0093[7]				10
1335-04-SUB[0]	1335-04-0164[3]	1335-04-0093[7]	1335-04-0078[1]			11
1335-04-SUB[0]	1335-04-0164[3]	1335-04-0093[7]	1335-04-0079[1]			11
1335-04-SUB[0]	1335-04-0164[3]	1335-04-0093[7]	1335-04-0098[1]			11
1335-04-SUB[0]	1335-04-0164[3]	1335-04-0093[7]	1335-04-0632[1]			11
1335-04-SUB[0]	1335-04-0164[3]	1335-04-0093[7]	1335-04-0632[1]	1335-04-5576[0]	1335-04-0149[1]	12

FIGURE 448
SCREENSHOT EXAMPLE OF ZONAL ANALYSIS REPORT DETAIL

FEEDER_ID	LCP	MED-DAY	INCID_ID	YEAR	MONTH	DAY	CUST	C&I	CUST-MINS	AOF	CAUSE
133504	93	yes	3877421	2019	2	24	329	36	40235.5	Primary	Trees
133504	93	no	3907322	2019	3	23	331	36	32075.2	Primary	Car Pole accident
133504	93	no	8132253	2019	5	19	270	30	26532	Primary	Weather
133504	93	no	8134565	2019	5	19	270	30	19208.3	Primary	Equipment Failure
133504	93	no	8135185	2019	5	19	328	36	73758.8	Primary	Trees - Outside ROW
133504	93	no	8214344	2019	7	20	111	12	20878	Primary	Animal
133504	93	no	8241968	2019	8	6	331	36	40636.2	Primary	Equipment Failure

Q. Does the Company consider other inputs when identifying potential LVD Repetitive Outages projects?

A. The LVD Planning group continuously collects feedback from customer-facing groups such as Economic Development and Customer Care to better understand the priorities and needs of customers to incorporate into the investment planning process. For example, a segment of line may not be experiencing multiple outages longer than five minutes. However, customers on that line might be experiencing brief interruptions causing their motors to restart and reduce production.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Repetitive Outages sub-program?

A. The Company is projecting LVD Repetitive Outages capital expenditures of $9,710,000, as shown in Exhibit A-31 (RTB-4), line 9, column (f).

Q. What has been the historical actual spending in the LVD Repetitive Outages sub-program for the past five calendar years?

A. The Company's historical actual spending in the LVD Repetitive Outages sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 13.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Spending in this sub-program has been on a generally downward trend because work that was historically completed in this sub-program was gradually moved to LVD Lines Reliability over the historical period. The purpose of this is to complete more work proactively rather than wait until a given circuit has experienced enough outages to trigger the need for a more reactive LVD Repetitive Outages project.

Q. What is the basis for the Company's requested spending level in the 2021 test year for the LVD Repetitive Outages sub-program?

A. The Company's requested spending level intentionally reverses the Company's downward trend in this sub-program and will allow the Company to complete approximately 300 repetitive outage projects. This spending level is necessary for the Company to meet the Commission's repetitive outage target in 2021, as the target was not met in 2019.

Q. Why did the Company not meet this target in 2019?

A. The Commission's repetitive outage target specifies a maximum of 5% of customers experiencing five or more Same Circuit Repetitive Interruptions, per rule R460.702(s) of the MPSC Service Quality and Reliability Standards for Electric Distribution Systems. In 2019, the Company's actual performance was 6.47%. The Company did not meet the target because of a higher-than-average number of smaller storms; in 2019, the Company experienced eight storms with greater than 50,000 customers interrupted, compared to a yearly average of five such storms. This 2019 system performance is in line with the system deterioration issues, particularly related to high wind, identified earlier in my direct testimony.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Repetitive Outages sub-program?

A. There is a direct correlation between SAIFI (including MEDs) and the MPSC's Repetitive Outage performance standard (which, by definition, includes storms). A statistical comparison of the two metrics, shown earlier in my testimony in Figure 15, indicates that once SAIFI (including MEDs) exceeds approximately 1.45, it becomes likely that the Repetitive Outage performance index standard will not be met. To improve customer satisfaction, the Company continues to focus on sustained SAIFI performance to meet the Repetitive Outage performance standard. A deteriorating SAIFI increases the probability that more than 5% of customers experience five or more Same Circuit Repetitive Interruptions per year. By targeting investment to the worst performing areas of our system, the Company expects to improve both SAIDI and SAIFI. This improves the customer experience through reduced outage length and the frequency of outages experienced.

As with the LVD Lines Reliability sub-program, targeted locations consistently see immediate benefits following an LVD Repetitive Outage project. For example, at Chapin substation, Marion circuit, zone 922, the recloser experienced one to four outages per year starting in 2014, causing outages for about 30 customers. In 2017, the Company added sectionalizing to the radial line. Subsequently, these customers experienced no interruptions in 2018 or 2019 due to this issue, saving approximately 7,000 customer outage minutes.

Furthermore, 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 sub-program reduce overall cost associated with emergent response for additional interruptions in the capital sub-program LVD Lines Demand Failures.

8. <u>Metro Reliability</u>

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the Metro Reliability sub-program.

A. The Metro Reliability sub-program ensures the long-term safe and reliable operation of the Company's six downtown Metro systems with investments to install and upgrade the civil and electrical assets that distribute electricity in those downtown cores. In this filing, Metro Reliability investments fall into two categories: (i) obsolete equipment replacements, and (ii) dead fronting equipment for safety.

Q. What types of work does the Company complete as part of obsolete equipment replacement projects?

A. The Company replaces functionally obsolete equipment, including:

- Oil-insulated switches with SF_6 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.

Q. What types of work does the Company complete as part of dead fronting equipment for safety?

A. The Company increases equipment safety by replacing:

- Live-front, dry type transformers, in buildings that fall under our "high rise policy" with dead front bushing well insert type and dry type transformer;
- Live-front, vault-style, transformers and fusing with molded vacuum interrupters;
- Encapsulated transformer bushings (fuses and elbow type) and live secondary buss with guarded load centers; and
- High rise live front transformer replacement.

Q. How does the Company identify reliability issues that would require a Metro Reliability project to address?

A. The Company reviews Metro Reliability projects during an annual planning cycle each year. While the Company continuously monitors the reliability of the Metro system, this annual review helps determine which line segments and components need to be addressed in a given year, as some projects may be large enough to span multiple years. Additionally, the Company determines which remediation strategy to use. Due to the lengthy customer interruptions that a Metro outage can cause, these projects are proactive to prevent an outage from occurring and not due to a previous interruption. Inputs the Company uses in its Metro line reliability assessment include:

- **Current system condition –** Metro condition is assessed based on safety and ability to operate existing equipment;
- **Customer base –** 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
- **Efficiency gains with other projects –** 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.

Q. How does the Company handle projects that require modified civil infrastructure?

A. For projects that require new or modified civil infrastructure, the Company releases the scope to a contracted civil engineering firm, who creates a feasibility study for a civil infrastructure path. The feasibility study provides a number of options for possible routes and estimated construction costs for those options. The Company engineer reviews the feasibility study with operations representatives to determine ease of construction and impact to future electric operations. The Company engineer notifies the civil engineering firm, who will prepare a design based on the selected option. The Company engineer will prepare an electrical design, cable pulling schedule, and electrical bill of materials. The civil engineering firm delivers the design and any documents needed to obtain a permit to perform work in the ROW from the Michigan Department of Transportation of the municipality, including a detailed traffic control plan.

Q. Please describe the types of risks encountered as part of this sub-program.

A. Risks that may be encountered during construction of Metro Reliability projects include:

- Encountering crushed conduit while attempting to replace cable. Conduit can be crushed as a result of heavy loaded objects above the ground or the fiberglass becoming brittle as a result of exposure to soil conditions;
- Increased costs associated with temporary transformation and other items required for a mobile vault. This is similar to the use of a mobile substation to allow for safe maintenance or construction work on de-energized equipment. It has a set of padmounted equipment built at grade level and fenced off to guard from the public; and
- Potential fluctuation in contractor costs. Contractor costs can fluctuate between projects based on the bids received. This is based on the amount of work that the contractor already has secured and the cost for them to add this to their work plan (additional or mobilizing resources).

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the Metro Reliability sub-program?

A. The Company is projecting Metro Reliability capital expenditures of $1,647,000, as shown in Exhibit A-xx (RTB-4), line 10, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated between the two investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 49 below.

FIGURE 459
METRO RELIABILITY INVESTMENT CATEGORY
EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Obsolete Equipment Replacement	$1,147,000	1
Dead Fronting Equipment for Safety	$500,000	2
Total	**$1,647,000**	

Q. What has been the historical actual spending in the Metro Reliability sub-program for the past five calendar years?

A. The historical actual spending in the Metro Reliability sub-program for the past five years is shown in Exhibit A-29 (RTB-2), line 14. .

Q. If spending in any of the five historical years is a significant outlier, please explain why this happened.

A. Spending in this sub-program may vary from year to year, since the Metro systems have a smaller number of projects than some other Reliability sub-programs, and those Metro Reliability projects can vary significantly in size and cost. Additionally, in 2017 and 2018 the Company spent lower amounts on Metro Reliability projects since there were fewer Metro Reliability needs during those years, and spending was allocated to other spending sub-programs to address higher-priority issues.

Q. What is the basis for the requested spending level for the Metro Reliability sub-program in this filing?

A. The Company is projecting to invest less than the typical historical spending for this sub-program in 2021, based on the Company's assessment of reliability needs for the Metro systems in 2021. The requested level of spending will enable the Company to (i) complete one obsolete equipment replacement project, and (ii) complete two dead fronting equipment for safety projects.

Q. Please list any prioritized projects that make up the requested spending level in the Metro Reliability sub-program for the 2021 test year.

A. As shown in Exhibit A-42 (RTB-15), page 22, line 7, the Company is planning one obsolete equipment replacement project costing $1,147,000, the Saginaw Water Street Civil and Electrical project. The Company developed a concept approval for this project, as shown in Exhibit A-41 (RTB-14), line 13. As shown in Exhibit A-42 (RTB-15), page 22, lines 8 and 9, the Company is planning two dead fronting equipment for safety projects in 2021. The Wolverine Vault Rebuild project is projected to cost $300,000, and the JC Penney Vault Deadfront project is projected to cost $200,000.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the Metro Reliability sub-program?

A. Metro Reliability investments minimize potential adverse impacts on customer experience by improving overall reliability and operation. These proactive investments also improve employee and public safety, through reduced outage incidents. Furthermore, investments in the Metro Reliability sub-program reduce overall cost associated with emergent response in the capital sub-program Metro Demand Failures.

9. <u>HVD Lines and Substations Rehabilitation</u>

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the HVD Lines and Substations Rehabilitation sub-program.

A. The HVD Lines and Substations Rehabilitation sub-program supports the capital repair or replacement of 46 kV and 138 kV lines and substation equipment to address issues where failure has not yet occurred, but is imminent, to maintain reliability. Work in this sub-program was historically performed in the HVD Lines and Substations Demand Failures sub-program. Like the HVD Lines and Substations Demand Failures sub-program, this sub-program consists of five investment categories: (i) pole replacements; (ii) pole top assembly replacements; (iii) switch (including MOABS) replacements; (iv) miscellaneous other replacements; and (v) HVD substation failure projects. The first four investment categories support projects on HVD lines.

Q. What types of work are included in each of these investment categories?

A. The types of work in each of these investment categories are the same as the types of work in their corresponding investment categories in the HVD Lines and Substations Demand Failures sub-program. The difference is that this sub-program deals with imminent failures, rather than actual failures.

Q. How does the Company assess if HVD lines assets face imminent failure?

A. The Company undertakes inspections of equipment to help determine if assets need repair or replacement, ensure components operate as intended, and maximize the value of those assets over their lifetimes, using four key inspection programs to help inform of potential actions to address lines failures. These proactive replacements are more economical, safer, and can save customer outage minutes compared to waiting for an actual failure. The four key HVD lines inspection programs informing the HVD Lines and Substations Rehabilitation sub-program are (i) pole inspections; (ii) helicopter inspections; (iii) biannual ground patrols, and (iv) MOABS testing.

Q. Please explain the pole inspections.

A. The Company inspects HVD poles on an approximate 12-year cycle. A contractor performs visual inspections, sonic inspections, and bore testing on all poles that are 11 years old or older along specified line sections. The bore test criteria that contractors are provided is shown in Figure 50 below.

FIGURE 50

Wood Pole Bore Test Criteria		
Original Ground Line Circumference (Inches)	**Reduction in Ground Line Circumference due to Exterior Decay (Inches)**	**Minimum Shell Thickness (Inches of Solid Wood)**
25 – 34	0 – 3	2.00
	Over 3 – Replace	-
34 – 39	0 – 3	2.50
	3 – 4	3.00
	Over 4 – Replace	-
39 – 45	0 – 3	3.00
	3 – 4	3.50
	Over 4 – Replace	-
45 – 55	0 -1	3.00
	2 – 4	3.50
	4 – 5	Solid Heart
	Over 5 – Replace	-
55 – 65	0 – 3	3.50
	3 – 6	Solid Heart
	Over 6 – Replace	-

Notes:

1. *Column 1: Original ground line circumference when installed.*
2. *Column 2: Reduction in ground line circumference after scraping away decayed wood.*
3. *If the reduction in ground line circumference falls into a range in Column 2, there must be at least the amount of solid shell wood that is listed in Column 3.*
4. *Visual inspection can be used to identify rejected poles where there is severe decay at the top of the pole or where the pole is split or has large voids above chest height or other similar conditions. Replacement may be recommended in cases of severe decay at the top of the pole following visual inspection.*

Q. Please explain the other three inspection programs.

A. The Company performs aerial inspections of its HVD lines system via helicopter. The results of the helicopter inspection program, as described in the Electric Engineering – HVD O&M Program section of my direct testimony, are a significant source of information to determine immediate action items. As an example, a flight conducted with a corona camera identified an insulator on one of the Company's 46 kV lines that was emitting a corona signature prompting an immediate replacement of the insulator to avoid a potential outage to the line and customers. The insulator in question was found to be cracked (which can result in emission of corona) and was in imminent failure status. For safety reasons, helicopters do not fly over approximately 400 miles of the HVD system. This is because it is difficult to land quickly and safely in the event of an emergency. Most of these "no-fly lines" are in urban areas. To inspect these lines, the Company completes biannual ground patrols, which may include infrared and/or corona inspection using handheld cameras. MOABS controls require power to operate and since they are called on to operate when the line they are attached to lose power, batteries provide control circuit power. Periodic battery replacement ensures that power is always available to operate the device. MOABS are tested annually, as described in the O&M Lines Reliability – HVD Program, to ensure the controls are in proper working order and the batteries are replaced every three to four years, or sooner as needed.

Q. How does the Company assess if HVD lines assets face imminent failure?

A. Inspection and evaluation of HVD substations allows the Company to identify equipment condition so that items can be replaced, if needed, before they fail and cause an outage to customers or reduce system operability. Some equipment (power transformers, station batteries, gas circuit breakers, and transformer bushings) are monitored by Field Technical Services and Substation Reliability Engineers and are replaced prior to failure through this sub-program. Some imminent failures are identified through monthly visual patrols performed by our Substation Operations group and are replaced through this program prior to failure.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the HVD Lines and Substations Rehabilitation sub-program?

A. The Company is projecting HVD Lines and Substations Rehabilitation capital expenditures of $38,921,000, as shown in Exhibit A-31 (RTB-4), line 11, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the five investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 51 below.

FIGURE 51
HVD LINES AND SUBSTATIONS REHABILITATION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Pole replacements	$5,671,000	274
Pole top assembly replacements	$1,840,000	296
Switch (inc. MOAB) replacements	$1,870,000	27
Miscellaneous other replacements	$640,000	24
HVD substation failure projects	$28,900,000	N/A
Total	**$38,921,000**	

Similar to the HVD Lines and Substations Demand Failures sub-program, the HVD substation failure projects investment category does not have projected units.

Q. What has been the historical actual spending in the HVD Lines and Substations Rehabilitation sub-program?

A. Because this is a newly-defined sub-program in this filing, historical actual spending for this sub-program is not available.

Q. What is the basis for the requested spending level for the HVD Lines and Substations Rehabilitation sub-program in this filing?

A. The HVD Lines and Substations Rehabilitation sub-program is a key component of the Company's plan to invest in overall reliability. This sub-program addresses those components of the distribution asset base that are most vulnerable to failure and corresponding interruptions to customers. By investing at the requested spending level, the Company will be able to (i) complete 274 "rush" pole replacements; (ii) complete 296 P3 pole top assembly replacements; (iii) complete 24 switch replacements; (iv) complete 24 miscellaneous other replacements; and (v) complete several HVD substation failure projects as discussed below.

Q. What are the historical unit costs for each of the HVD Lines and Substations Rehabilitation investment categories?

A. Historical unit costs for this sub-program are the same as those in the HVD Lines and Substations Demand Failures sub-program, as shown in Figure 30.

Q. How will the Company identify projects for the four HVD lines-related investment categories for the 2021 test year?

A. The Company has not yet identified projects for the 2021 test year in the pole replacements, pole top assembly replacements, switch replacements, or miscellaneous other replacements investment categories. Each of these investment categories in this sub-program respond to imminent needs on the system, even though they are not as high-priority as HVD Lines and Substations Demand Failures projects that respond to actual failures that have already occurred. During 2020, the Company and its contractors will conduct ground patrols to identify pole replacement projects and helicopter inspections to identify pole top assembly replacement projects and will rely on reports from field employees to identify switches and other equipment in need of replacement. The Company's projected spending in these four categories is generally in line with historical actual spending on imminent failures.

Q. Please list any prioritized projects that make up the requested spending level in the HVD substation failure investment category in the HVD Lines and Substations Rehabilitation sub-program for the 2021 test year.

A. The Company plans to complete two large transformer replacement projects at HVD substations, with each project costing $1,800,000. One of these projects will take place at Barry Substation, and the other will take place at Bass Creek substation. Additionally, the Company is planning to complete the first half of two separate two-year HVD substation replacement projects. One project will replace the Morrow substation near Kalamazoo, which is in an end-of-life condition, with $6,100,000 of spending in 2021. The other will replace the Higgins substation, with $4,800,000 of spending in 2021. Finally, the Company will complete a full rebuild of the Twining substation, with $9,500,000 of spending in 2021. These projects are identified in Exhibit A-42 (RTB-15), page 22, lines 11 through 15. The Company developed concept approvals for these projects, as listed in Exhibit A-41 (RTB-14), lines 14 and 15. The Company will identify additional HVD substation failure projects later in 2020 based on inspection results.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the HVD Lines and Substations Rehabilitation sub-program?

A. This sub-program addresses areas on HVD lines and in HVD substations where failures, and corresponding outages and customer interruptions, are particularly likely. Addressing degrading equipment reduces the likelihood of failure. This is particularly important in this sub-program, as outages on the HVD system often result in a high number of customer interruptions.

10. <u>LVD Substations Rehabilitation</u>

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the LVD Substations Rehabilitation sub-program.

A. The LVD Substations Rehabilitation sub-program includes capital repair or replacement of LVD substation equipment that has not actually failed, but that has been assessed to be at imminent risk of failure. Much of this work was formerly included in the LVD Substations Demand Failures sub-program, but now takes place in this newly-created sub-program as discussed earlier in the Demand Failures section of my direct testimony. The LVD Substations Rehabilitation sub-program also includes work that was formerly included in the LVD Substations Reliability sub-program, including projects to address working clearance code violations, replacement of 138 kV spring-operated ground switches (“SOGS”) and 138 kV fuses with a three-phase interrupting device, and replacement of obsolete equipment. Obsolete equipment includes reclosers, breakers, fuses, regulators, lightning arrestors, and switches that can no longer be purchased from manufacturers, and with depleting inventory and replacement parts.

Q. What are the inputs used to determine what equipment may be in an imminent failure status?

A. Imminent failures are identified by monitoring and tracking LVD substation equipment and components utilizing various means of analysis such as dissolved gas analysis (“DGA”) and infrared data. These analyses help to identify specific locations to target corrective action based on probability of an unplanned event, and to prioritize projects that will deliver the greatest reliability impact based on specific metrics (e.g., SAIDI and SAIFI). Proactively replacing deteriorated equipment that is deemed as an imminent failure in advance of an actual equipment failure is more economical as it typically avoids customer outages and costly overtime. Some imminent failures are identified through monthly visual patrols performed by our Substation Operations group and are replaced through this program prior to failure. The cadence of the LVD substation equipment evaluation and inspection is found in Figure 52 below.

Figure 46:

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)
	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

Q. Do any other operating organizations or departments provide inputs into this sub-program?

A. Yes. Input from operating organizations and other departments inform the substation planning engineers with operational concerns and system constraints that may trigger a need for projects to resolve working clearance code violations and replacement of obsolete equipment.

Q. What investment categories are included in the LVD Substations Rehabilitation sub-program?

A. The LVD Substations Rehabilitation sub-program includes: (i) Allis Chalmers substation transformer replacements; (ii) equipment replacement and regulatory-related projects, which include end-of-life condition substation rebuilds, addressing working clearance code violations, and other targeted replacements of specific equipment, such as 138 kV fuses and 138 kV SOGS, and obsolete reclosers, breakers, fuses, regulators, lightning arrestors and switches; and (iii) targeted replacement of transformers at risk of imminent failure.

Q. Please describe the Allis Chalmers substation transformer replacement investment category.

A. Allis Chalmers mid-20th century vintage substation power transformers were produced with a design deficiency associated with the top clamping structure of the transformer windings. The key purpose of the clamping structure is to prevent winding movement. This deficiency results in an inherent weakness of the transformer to withstand the forces accompanying certain magnitude low side faults. Winding movement typically results in electrical shorts and arcing, which lead to excessive heating, creation of combustible gasses, and eventual failure of the transformer.

Q. How many of these Allis Chalmers substation transformers are in-service and what has the Company's recent experience been with these transformers?

A. On its LVD substations, the Company has 60 of these Allis Chalmers units in-service in their original design, and another 16 rewound units in-service which are considered at risk of developing the condition, for a total of 76 units. Approximately 28% of the substation transformer failures experienced in the past five years have been from this vintage and manufacturer.

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: Nine transformers replaced; eight transformers within the LVD Substations Demand Failures Program and one transformer as part of an LVD Substations Capacity project;
- 2018: 10 transformers replaced within the LVD Substations Demand Failures Program;
- 2019: 15 transformers replaced; 13 transformers within the LVD Substations Demand Failures Program and two transformers as part of LVD Substations Reliability projects; and
- 2020: 12 transformer replacements planned within the LVD Substations Rehabilitation Program, and one transformer replacement planned as part of an LVD Substations Capacity project.

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 2021 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 at its LVD substations in the late 2010's, it discovered that some of the substations did not meet the NESC working space requirements and began a process of addressing all of these working space issues by 2028.

Q. How does the Company treat obsolete equipment in this sub-program?

A. When specific types of equipment can no longer be purchased from manufacturers, replacement parts can no longer be purchased, and inventory levels are depleting, equipment is classified by the Company as obsolete. Targeted replacements are implemented because new equipment may not fit into the same location without structural substation modifications due to physical size, mounting requirements and electrical clearance requirements.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Substations Rehabilitation sub-program?

A. The Company is projecting LVD Substations Rehabilitation capital expenditures of $14,500,000, as shown in Exhibit A-31 (RTB-4), line 12, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the three investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 53 below.

FIGURE 53
LVD SUBSTATIONS REHABILITATION INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Allis Chalmers transformer replacements	$9,000,000	16
Equipment replacement and regulatory	$3,700,000	40
Transformers at imminent risk of failure	$1,800,000	3
Total	**$14,500,000**	

Q. What has been the historical actual spending in the LVD Substations Rehabilitation sub-program?

A. Because this is a newly-defined sub-program in this filing, historical actual spending for this sub-program is not available.

Q. What is the basis for the requested spending level for the LVD Substations Rehabilitation sub-program in this filing?

A. The LVD Substations Rehabilitation sub-program is a key component of the Company's plan to invest in overall reliability. This sub-program addresses those components of the LVD substation asset base that do not meet working clearance requirements and/or are most vulnerable to failure and corresponding interruptions to customers. By investing at the requested spending level, the Company will be able to (i) replace 16 Allis Chalmers transformers; (ii) address working clearance code issues at six substations, and complete 34 obsolete equipment replacements (recloser, switch, and fuse replacements) at three substations; and (iii) replace three transformers with imminent failure concerns.

Q. Please list any prioritized projects that make up the requested spending level in the Allis Chalmers substation transformer replacements investment category in the LVD Substations Rehabilitation sub-program for the 2021 test year.

A. The Company has identified 16 Allis Chalmers substation transformer replacements, at 13 substations, for the 2021 test year, which are listed in Exhibit A-42 (RTB-15), page 22, lines 18 through 30. The Company developed concept approvals for this work, as listed in Exhibit A-41 (RTB-14), line 16.

Q. Are there circumstances in which Allis Chalmers transformer replacements could be reprioritized?

A. Over the next several years, the Company plans to replace the 76 remaining Allis Chalmers transformers at all of the LVD substations. The Company prioritizes which ones to replace in a given year based on DGA testing results. While the Company has identified the projects in Exhibit A-42 (RTB-15), page 22, lines 18 through 30, for the 2021 test year, the Company could reprioritize and target different transformers if testing results in 2020 indicated that reprioritization was justified.

Q. Please list any prioritized projects that make up the requested spending level in the equipment replacement and regulatory-related investment category in the LVD Substation Rehabilitation sub-program for the 2021 test year.

A. The Company has identified six substations for working space projects for the 2021 test year, which are listed in Exhibit A-42 (RTB-15), page 22, lines 31 through 36. The Company has also identified 34 projects to replace obsolete equipment at four substations, as listed in Exhibit A-42 (RTB-15), page 22, lines 37 through 40.

Q. Please list any prioritized projects that make up the requested spending level in the transformers at risk of imminent failure investment category in the LVD Substations Rehabilitation sub-program for the 2021 test year.

A. The Company has identified three transformers at risk of imminent failure for replacement in 2021, as listed in Exhibit A-42 (RTB-15), page 22, lines 41 through 43.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Substations Rehabilitation sub-program?

A. This sub-program works to address areas in LVD substations where working space is insufficient, or where failures, and corresponding outages and customer interruptions, are particularly likely. Addressing degrading equipment reduces the likelihood of failure.

11. LVD Lines Rehabilitation

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the LVD Lines Rehabilitation sub-program.

A. The LVD Lines Rehabilitation sub-program includes capital repair or replacement of LVD lines equipment that has not actually failed, but that has been assessed to be at risk of failure in the near term. This work was formerly included in the LVD Lines Demand Failures sub-program, but now takes place in this newly-created sub-program as discussed earlier in the Demand Failures section of my direct testimony. This sub-program consists of two investment categories: (i) security assessment repairs, and (ii) imminent rehabilitation. The imminent rehabilitation investment category was formerly known as "emergent rehabilitation."

Q. Please explain the security assessment repairs investment category.

A. The Company inspects approximately 300 overhead circuits for this category annually. Based on the results of these security assessments, the Company identifies anomalies that must be repaired based on priority codes, discussed below. This category addresses issues that the Company discovers during LVD overhead line inspections. The LVD overhead line inspection category is completed on a six-year cycle. The overhead line inspection category evaluates all equipment on a structure, including the pole, through a visual inspection process. The circuits are assessed by completing driving inspections to identify public safety hazards along with failed, end-of-life, defective, and obsolete equipment.

Q. How does the Company prioritize projects in this category?

A. Prioritization codes are used to classify issues and determine how quickly they must be addressed. As discussed in my section on LVD Lines Demand Failures, P1 and P2 issues are addressed within that sub-program. Figure 54 below presents the types of hazards, which are Priority 3 ("P3") and Priority 4 ("P4"), found during security assessments. The hazards are listed by the priority code for the anomaly. The Company strives to address P3 and P4 issues within two years.

FIGURE 474
LVD SECURITY ASSESSMENT HAZARD CODES

Code	Description
P3 - Failure Expected Before Next Inspection (Less Than 6yrs)	
P3A	Pin Pulling from Cross-arm / Pole
P3B	Cracked Cross-arm
P3C	Broken Guy - Leaning Pole
P3D	Pole: Damaged
P4 - Heightened Risk of Failure	
P4A	Broken/Missing Cross-arm Braces
P4B	Failed Arrester
P4C	Broken Guy - Non-Leaning Pole
P4D	Damaged Equipment (Transformers, Reclosers, Etc.)
P4E	Lightning/Flashover Burn Marks
P4F	Poorly Sagged Line
P4G	Pin Through Cross-arm

Q. Please explain the imminent rehabilitation investment category.

A. The imminent rehabilitation category addresses emergent issues that arise in which an actual failure has not occurred, but in which repair or replacement is required. Imminent rehabilitation projects deal with conditions identified outside our inspection cycles and normal planning work, but when there is not an immediate need for repair as with LVD Lines Demand Failures projects. Imminent rehabilitation projects include:

- **P3 and P4 Overhead Prioritization Codes** – P3 and P4 conditions, as identified in Figure 54 above, may be addressed in this investment category when found outside of the inspection process;

- **Underground Cable Repair** – After a fault is isolated and customers are restored, as discussed above under service restoration activities, the underground cable is no longer looped (i.e., no longer has feeds from multiple directions) and needs to be put back into service. If the faulted section is left isolated for a long period of time, it would risk having another failure in this area, and there would no longer be a way to restore service to customers from that direction. If this is the first time the section of line has faulted, the Company typically will expose the fault and splice it. If this section or area has experienced multiple faults or the vintage of the cable warrants replacement, the Company will develop a project to replace the faulted section of cable and, in some cases, adjacent sections of cable as well;

- **Underground Padmount Equipment –** Padmount equipment may require relocation or replacement due to ground shifting that causes leaning or sinking; and

- **Underground Padmount Equipment Inspections –** Every year, padmounted equipment is visually inspected around the exterior for any signs of oil leaking or holes that expose electrical components. When found, the equipment is replaced, and any environmental issues are mitigated.

Q. Please describe the general inputs that the Company uses to identify issues that must be addressed by the LVD Lines Rehabilitation sub-program.

A. The Company collects data through its Field Operations organization. For example, there may be locations that Field Operations have frequently visited to restore service for a failed underground cable in the same subdivision. This team relays this information to circuit planners so they can investigate and create a concept project for a full replacement of the underground cable and possibly live front transformers or padmounted switching equipment in that subdivision if necessary.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Lines Rehabilitation sub-program?

A. The Company is projecting LVD Lines Rehabilitation capital expenditures of $37,723,000, as shown in Exhibit A-31 (RTB-4), line 13, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the three investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 55 below.

FIGURE 48
LVD LINES REHABILITATION INVESTMENT CATEGORY
EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Security assessment repairs	$25,830,000	215
Imminent rehabilitation	$11,893,000	4,115
Total	**$37,723,000**	

Q. What has been the historical actual spending in the LVD Lines Rehabilitation sub-program for the past five calendar years?

A. Because this is a newly-defined sub-program in this filing, historical actual spending for this sub-program has only been tracked since 2018, as shown in Exhibit A-29 (RTB-2), line 20.

Q. Please explain the year-over-year decrease from 2018 to 2019.

A. In 2018, this sub-program included spending on targeted zone improvements due to deterioration. Beginning in 2019, all such spending was moved into the LVD Lines Reliability sub-program, under the target circuit improvements investment category that I described in that section of my direct testimony.

Q. What is the basis for the requested spending level for the LVD Lines Rehabilitation sub-program in this filing?

A. The Company's projected spending on imminent rehabilitation is in line with its historical spending in the emergent rehabilitation investment category that was historically located in the LVD Lines Demand Failures sub-program. As discussed earlier in my direct testimony, system deterioration is more significant than was known when the Company developed its 2018 EDIIP, leading the Company to increase its investment in key

Reliability Program areas. Security assessment repairs is one investment category in which the Company is planning to increase its investment.

Q. What are the historical unit costs for each of the LVD Lines Rehabilitation investment categories?

A. These investment categories were historically included in the LVD Substations Demand Failures sub-program. Historical unit costs for each category, when they were part of that sub-program, are provided in Figure 56 below:

FIGURE 49
LVD LINES REHABILITATION INVESTMENT CATEGORY UNIT COSTS

Investment Categories	*2014*	*2015*	*2016*	*2017*	*2018*
Security assessment repairs	$14,100/order	$9,600/order	$13,000/order	$15,400/order	$13,900/order
Imminent rehabilitation	$3,900/order	$4,900/order	$4,300/order	$6,700/order	$10,000/order

Q. Please explain any variation in unit costs over time.

A. Security assessment repairs and imminent rehabilitation can vary due to variations in size and complexity of work orders. The cost for imminent rehabilitation increased in 2017 due to post storm assessments after the March 2017 catastrophic wind storm. In 2018, The Company performed a higher amount of underground imminent rehabilitation work.

Q. Are there any prioritized projects that make up the requested spending level in the security assessment repairs investment category in the LVD Lines Rehabilitation sub-program for the 2021 test year?

A. The Company has identified 215 security assessment repair projects for the 2021 test year, which are listed in Exhibit A-42 (RTB-15), page 23, line 1, through Exhibit A-42

(RTB-15), page 26, line 53. The Company has developed concept approvals for projects in this investment category, as shown in Exhibit A-41 (RTB-14), line 18.

Q. Are there any prioritized projects that make up the requested spending level in the imminent rehabilitation investment category in the LVD Lines Rehabilitation sub-program for the 2021 test year?

A. As discussed above, projects are not planned far in advance in this investment category, because the investment category is meant to quickly respond to equipment failures and customer interruptions that have already taken place. The Company expects to complete the number of projects identified for this investment category in my testimony, which will be identified and executed during the test year.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Lines Rehabilitation sub-program?

A. While the LVD Lines Demand Failures sub-program addresses situations in which equipment has already failed, the LVD Lines Rehabilitation sub-program addresses imminent failure conditions that could result in interruptions to customer(s) or create unacceptable system operating conditions, and therefore provides a reliability benefit by reducing the likelihood of future actual failures. Since these investments are planned and targeted at areas of the system most likely to fail, they reduce outage frequency. And, by replacing or rehabilitating equipment before it fails, work can be completed in a more economical manner.

12. Metro Rehabilitation

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the Metro Rehabilitation sub-program.

A. The Metro Rehabilitation sub-program addresses assets on the Company's Metro systems that have been identified as being at a high risk of imminent failure, such that replacement is justified based on potential risks to public safety, employee or contractor safety, or to maintain the reliability of the Metro systems. Work in the Metro Rehabilitation sub-program was historically done in the Metro Demand Failures sub-program, before the work was reclassified, as I described earlier in my direct testimony in the section on the Demand Failures Program. The Metro Rehabilitation sub-program consists of two investment categories: (i) crushed duct replacements; and (ii) vault or manhole roof replacements.

Q. Please explain crushed duct replacements.

A. When an existing duct bank has been crushed or is deteriorated, it is replaced with a new concrete-encased duct bank. New cable is also run to replace the damaged cable.

Q. Please explain vault or manhole roof replacements.

A. Vault and manhole roofs require replacement when the existing roof is damaged or deteriorated. This situation creates safety hazards to the public passing over it and anyone entering the structure.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the Metro Rehabilitation sub-program?

A. The Company is projecting Metro Rehabilitation capital expenditures of $4,353,000, as shown in Exhibit A-31 (RTB-4), line 14, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the three investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 57 below.

FIGURE 50
METRO REHABILITATION INVESTMENT CATEGORY
EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Crushed duct replacements	$1,353,000	1
Vault or manhole roof replacements	3,000,000	2
Total	**$4,353,000**	

Q. What has been the historical actual spending in the Metro Rehabilitation sub-program?

A. Because this is a newly-defined sub-program in this filing, historical actual spending for this sub-program is not available.

Q. What is the basis for the requested spending level for the Metro Rehabilitation sub-program in this filing?

A. The Metro Rehabilitation sub-program is a key component of the Company's plan to invest in overall reliability. This sub-program addresses those components of the Metro asset base that are most vulnerable to failure and corresponding interruptions to customers. By investing at the requested spending level, the Company will be able to (i) complete one crushed duct replacement; and (ii) complete two vault or manhole roof replacements.

Q. Are there any prioritized projects that make up the requested spending level in the Metro Rehabilitation sub-program for the 2021 test year?

A. As shown in Exhibit A-42 (RTB-15), page 27, lines 1 and 2, the Company has identified two projects in the vault or manhole roof replacements investment category, each costing $1,500,000. These are the Association of Commerce Vault Replacement project and the Louis Ionia Vault Replacement project. As shown in Exhibit A-42 (RTB-15), page 27, line 3, the Company has identified one crushed duct replacement project, costing $1,353,000. This is the Saginaw Janes Avenue project. The Company developed concept approvals in support of these projects, as shown in Exhibit A-41 (RTB-14), lines 19 and 20.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the Metro Rehabilitation sub-program?

A. Upgrading and replacing degraded components in the Metro system allows the Company to maintain a redundant system in the downtown areas of cities, providing a reliability benefit. This benefit directly impacts courthouses, jails, municipal offices, police and fire departments, as well as many businesses and residents. A Metro system in good condition allows employees and contractors to work in a safe environment and supports public safety. Investing in the Metro system to alleviate failure conditions allows customers not to be single-sourced as the Company isolates manholes and vaults for repair.

13. <u>Grid Storage</u>

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the Grid Storage sub-program.

A. Grid Storage is a new sub-program that will allow the Company to develop its battery strategy. The capital expenditures in the Grid Storage sub-program will install new batteries on the Company's electric distribution system.

Q. What is the Company's battery strategy as it relates to electric distribution?

A. The Company's battery strategy considers two simultaneous trends. First, the Company expects that the capital costs for battery installation will continue on their downward trend for at least the next several years, meaning they will eventually become a viable and critical part of the Company's electric supply portfolio. Second, intermittent renewable generation is expected to increase its penetration on the grid, particularly solar generation; the Company's IRP proposed a significant build-out of distributed solar generation. As solar generation claims a larger share of the generation mix, it introduces challenges related to intermittency and peak alignments; batteries can help smooth out the intermittency of solar generation and can store electricity generated by solar facilities at off-peak times for discharge during peak times. Given these two trends, the Company anticipates that by the 2025 to 2032 timeframe, large scale investments in battery storage will be necessary to appropriately manage the grid. In the short-term, the Company is investing in smaller deployments of battery storage to test battery capabilities and develop Company expertise at operating battery systems, building on the lessons that the Company has already learned from its Parkview battery in Kalamazoo and its Circuit West battery in Grand Rapids.

Q. What is included in these smaller deployments?

A. To build on the Company's progress with Parkview and Circuit West, the Company is planning three additional battery projects to develop further capabilities. The first of these, to be substantially completed in 2020, with final completion in early 2021, will install a battery at a solar farm under development in Cadillac. This battery will be connected to the direct current side of the inverter at the solar farm, which will give the Company the ability to make the solar generation dispatchable and to engage in direct smoothing of the solar generation profile. In addition to these capabilities, this battery will be more efficient in operation than the Parkview battery, which is connected to the alternating current side of the inverter and therefore more separated from its corresponding solar farm.

The second project, which will begin in 2020 and be completed in 2021, will deploy a portable battery on the system. The primary purpose of this battery will be to defer a projected substation capacity upgrade. By connecting to the substation, the battery will provide peak load shaving to extend the life of the substation. If the substation experiences continued load growth, and the capacity upgrade is needed in a future year, then the portable nature of the battery would allow it to be transported and connected to the distribution system at a different location, providing similar and continued benefits to customers.

The third project, which will begin in 2020 and continue through 2021 to a completion in 2022, will install a battery on the system that is designed to allow islanding, in order to mitigate potential outages on the circuit by continuing service to customers while an outage is restored.

Q. What further benefits will the Grid Storage sub-program provide to customers?

A. The use of batteries to defer capital investments, as is the case with the planned portable battery, has great potential to reduce customer costs, adding to the expected contribution of batteries as an economical electric supply solution. Use of batteries will also provide insights regarding voltage control and the potential for electric market savings, both to the direct benefit of customers.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the Grid Storage sub-program?

A. The Company is projecting Grid Storage capital expenditures of $10,000,000, as shown in Exhibit A-31 (RTB-4), line 15, column (f). Because this is a new sub-program in this filing, there is no historical spending.

Q. What is the basis of the Company's requested spending level in this filing for the Grid Storage sub-program?

A. The Company's projected spending in the 2021 test year will fund the completion of the solar farm battery and the portable battery, and continued work on the islanding battery, as discussed above. In the 2021 test year, the Company is projecting to spend $200,000 on the solar farm battery, $8,131,000 on completion of the portable battery and $1,669,000 on work for the islanding battery. These projects are listed in Exhibit A-42 (RTB-15), page 27, lines 5 through 7. The Company developed concept approvals for these projects, as listed in Exhibit A-41 (RTB-14), lines 21 and 22.

Q. Are there costs included in the Company's request for which specific projects have not yet been identified?

A. No.

E. Capacity Program

Q. What is the purpose of the Capacity program?

A. The Capacity program is designed to (i) ensure that the HVD system is capable of serving forecasted electric peak demand when all HVD facilities are in-service; (ii) ensure that individual HVD facilities can be taken out of service during non-peak demand periods without loading equipment beyond ratings of providing unacceptably low voltage; and (iii) fix LVD equipment loads after they occur. In general, projects in this program consist of either upgrading the size of assets so they can accommodate more load or installing new assets to relieve load on existing assets. Additionally, the Capacity program includes new sub-programs designed to implement elements of the Company's IRP: the CVR sub-program includes work to put that component of the Company's IRP into effect, while the Interconnections sub-programs will allow the Company to add new solar generation to the grid. The sub-programs of the Capacity program in this filing are: (i) LVD Lines Capacity; (ii) HVD Lines and Substations Capacity; (iii) LVD Substations Capacity; (iv) LVD Transformers Capacity; (v) LVD New Business Capacity; (vi) CVR; (vii) HVD Lines Interconnections; and (viii) HVD Substations Interconnections.

Q. To what extent are Capacity Program investments "planned?"

A. Each Capacity sub-program consists primarily of investments that are discretionary, in that they do not respond to an emergency, meaning the Company has some ability to prioritize and reprioritize its projects in these sub-programs. Because of this, the Company may, during the 2021 test year, pull forward projects that originally would not have been anticipated until later if conditions warrant. For example, if unexpected load growth caused an LVD asset to be overloaded earlier than anticipated, the Company could pull forward a Capacity project to address that asset.

Q. What is the Company's total projected investment in the Capacity Program in this case, and what is the basis for this level of investment?

A. As shown in Exhibit A-32 (RTB-5), line 11, column (c), the Company's 2019 Capacity Program spending was projected to be $56,220,000, consistent with recent historical levels. Capacity Program spending remains constant in the 2020 bridge year, when the Company is projecting $56,640,000 in total Capacity spending, as shown in Exhibit A-32 (RTB-5), line 11, column (d). For the 2021 test year, the Company projects to spend $66,323,000, as shown in Exhibit A-32 (RTB-5), line 11, column (f). Projected 2021 spending is explained in greater detail in the Capacity sub-program sections below.

1. LVD Lines Capacity

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the LVD Lines Capacity sub-program.

A. Capital investments in the LVD Lines Capacity sub-program prevent overloads that would result from increased demand on the LVD system, load growth, or load shifting from one area to another. These investments fund critical projects to address capacity loading issues in accordance with planning criteria, and to address new load additions, to ensure that the LVD system can meet projected distribution loads. Investments in this sub-program are divided into two categories: (i) equipment upgrades, and (ii) lines capacity projects associated with substation projects. Historically, this sub-program also included work to upgrade equipment based on new business growth, but that work is included in this filing in a separate sub-program, LVD New Business Capacity.

Q. Why does the Company invest in LVD Lines Capacity projects to upgrade or replace overloaded lines and equipment?

A. The Company upgrades or replaces overloaded lines and equipment to reduce reliability and safety risks, including equipment failure; nuisance disruptions of sectionalizing devices (e.g., fuse links melting); potential oil spills; equipment heating with a potential risk of fire; and conductor melting or sagging, creating a public safety hazard of potential contact.

Q. Why does the Company invest in LVD Lines Capacity projects to address substation capacity projects associated with line work?

A. Since substations are part of the backbone infrastructure of the electric distribution network, LVD Lines Capacity projects must be completed to reduce the risk of failure due to substation equipment reaching capacity limits.

Q. How does the Company identify capacity issues that would require an LVD Lines Capacity project to address?

A. The Company's project selection follows three steps: (i) considering peak loads; (ii) comparing peak loads to failure criteria; and (iii) ranking components by their percentage of overload.

Q. What is the significance of considering peak load in this sub-program?

A. All planning activities in this sub-program are based on projected peak load conditions, which is when capacity is most challenged. The Company uses normal, or continuous, ratings for peak load conditions, due to the heightened risk of equipment failure or degradation when operating above the capability rating. The loadings on equipment are established by the manufacturer, or by a recognized industry source such as IEEE, and specify the optimal operation of the equipment based on the capability characteristics of the components. The specific evaluation of each piece of equipment depends on its use. For example, equipment using oil is rated based on a temperature limit not to be exceeded. If that operating temperature is exceeded, then the equipment can start to break down and possibly lead to a shorter lifespan. Other equipment has a defined set of characteristics that, when taken beyond the manufacturer specifications, can lead to a change in characteristics of the material, altering its strength and durability.

Q. Please describe the Company's power flow study process to evaluate the LVD system's ability to handle peak loads.

A. The Company evaluates the LVD system using CYME, an industry-standard power flow software, to perform a power flow analysis. CYME uses load information from two databases to perform power flow studies, the Feeder Demand database and the Customer Loads database. The Feeder Demand database provides the maximum amperage experienced on the circuit with data from substation metering equipment. The Customer Loads database uses customer meter data. The CYME power analysis compares the Feeder Demand load at the substation to the Customer Load distributed across the circuit to determine power flow, voltages, and system protection needs. This analysis is performed on current and future states of the system. This process identifies overloaded distribution equipment and instances of unacceptably low or high voltage during system peak load conditions.

Q. How often does the Company conduct these power flow studies?

A. The Company typically evaluates loading on its LVD distribution equipment, utilizing CYME, on an annual basis, for capacity planning purposes. Additionally, studies are completed throughout the year to address emergent issues such as load transfers, generator interconnections, and reliability failures.

Q. After the power flow study is performed, how does the Company determine if an LVD Lines Capacity project is required?

A. Capacity planning criteria requires that a component of the distribution system have a projected load higher than its capacity, based on Company standards for capacity, before developing a potential capacity project. At present, this requires that a component of the distribution system experience a load in excess of its capacity a minimum of one year prior to a capacity project being initiated.

Q. What other factors does the Company consider when determining if an LVD Lines Capacity project is required?

A. Previous year loadings and future customer growth are taken into account when projecting future loadings. While most equipment has emergency ratings that enable higher capacity for short durations, these are not considered during capacity planning, since loading at these higher levels results in degradation and eventual failure.

Q. After LVD Lines Capacity projects are proposed, how does the Company prioritize which projects to build?

A. 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.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Lines Capacity sub-program?

A. The Company is projecting LVD Lines Capacity capital expenditures of $11,321,000, as shown in Exhibit A-32 (RTB-5), line 1, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the two investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 58 below.

FIGURE 51:
LVD LINES CAPACITY INVESTMENT CATEGORY
EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Overloaded equipment upgrades	$8,346,000	58
Lines capacity projects assoc. w/ substation work	$2,975,000	6
Total	**$11,321,000**	

Q. What has been the historical actual spending in the LVD Lines Capacity sub-program for the past five calendar years?

A. The Company's historical actual spending in the LVD Lines Capacity sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 24.

Q. Please explain the year-over-year variation in spending in this sub-program.

A. Beginning in 2018, the Company began treating LVD New Business Capacity as a separate sub-program, resulting in lower spending in the overall remaining LVD Lines Capacity sub-program. Additionally, in 2019, significant increases in emergent LVD New Business, Asset Relocations, and Demand Failures work, as discussed elsewhere in my direct testimony, required the Company to shift resources away from LVD Lines Capacity to focus on those emergent issues.

Q. What is the basis for the requested spending level for the LVD Lines Capacity sub-program in this filing?

A. The requested spending level of $11,321,000 is in line with the Company's spending in this sub-program in prior years. The level of spending requested in this filing will enable the Company to complete (i) 58 overloaded equipment upgrade projects, and (ii) six lines capacity projects associated with substation work.

Q. Are there any prioritized projects that make up the requested spending in the LVD Lines Capacity sub-program for the 2021 test year?

A. 58 prioritized overloaded equipment upgrade projects have been identified, as listed in Exhibit A-42 (RTB-15), page 27, line 9, through Exhibit A-42 (RTB-15), page 28, line 16. Six projects for line work associated with substation work have been identified, as listed in Exhibit A-42 (RTB-15), page 28, lines 17 through 22. The Company has developed concept approvals for projects in this sub-program, as listed in Exhibit A-41 (RTB-14), lines 23 and 24.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Lines Capacity sub-program?

A. This sub-program prevents future failures that increase SAIDI. Additionally, work in this sub-program can provide benefits associated with forestry, as capacity projects generally include some line clearing work that benefits the larger system. The investments made to upgrade overloaded assets and alleviate voltage issues increase the longevity of the equipment and prevents service issues/interruptions to customers while improving employee and public safety.

2. HVD Lines and Substations Capacity

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the HVD Lines and Substations Capacity sub-program.

A. This sub-program addresses capacity needs on the HVD system through work in five investment categories: (i) Load Carry Capabilities and Voltage Support; (ii) New Interconnections; (iii) Improved Functionality; (iv) Coordination with Transmission; and (v) ROW Procurement.

Q. What projects are funded through the Load Carrying Capabilities and Voltage Support investment category?

A. The Load Carrying Capabilities and Voltage Support category contains projects that eliminate unacceptably low voltage, and loadings above line and equipment ratings. 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. Through this process, HVD facilities are identified that would violate 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. The Company's plans to fix projected criteria violations are tested in the models to ensure they fulfill their designed purpose. SCADA information is also used to project future load on the HVD system. The short circuit model of the HVD network compares the available short circuit current to the interrupting capability of the HVD interrupting equipment. These capacity projects must be completed on an as-needed basis, based on projected loading in power flow models. 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 actually occurs in subsequent years.

Q. What projects are funded through the New Interconnections investment category?

A. The New Interconnection category contains new interconnections to LVD substations, other utilities, and generation facilities that must be completed as requested by the interconnecting party. Costs to interconnect other utilities and generation facilities to our HVD system are reimbursed by the other utilities or generators being interconnected.

Q. What projects are funded through the Improved Functionality investment category?

A. The Improved Functionality category contains projects that are completed to meet changes in standards and upgrades to protective schemes on a planned basis over a period of time. An example of this is the Company alleviating substation NESC working space issues systematically over a 10-year period. It is often coordinated with other major projects as they occur at the same location. Configuration changes to improve operability are made at the request of the Grid Management group, or through coordination with other major projects as they occur at the same location.

Q. What projects are funded through the Coordination with Transmission investment category?

A. The Coordination with Transmission projects, such as HVD relay upgrades associated with transmission upgrades, must be coordinated with those transmission upgrade projects that require the HVD upgrades to be completed. These are completed as needed over time in conjunction with the transmission owner.

Q. What projects are funded through the ROW Procurement investment category?

A. The ROW Procurement projects are necessary to procure HVD line rights or substation sites. These projects are critical to prepare for HVD construction and can require significant lead time. Acquiring the necessary land, or land rights, is key and integral to advancing HVD lines and substation projects across multiple capital sub-programs. These projects must be prioritized to adequately support the project that is depending on the new rights (e.g., new HVD line, HVD line relocation or rebuild off-center, new HVD or LVD substation, or improved easements where rights are determined to be inadequate). As an example, through the process of monitoring and studying load profiles, properties are sought and procured in order to build electric infrastructure at the right point in time needed to serve our customers.

Q. Please describe the HVD capacity planning criteria for the HVD lines and substations.

A. The HVD lines and substation planning criteria specify that the HVD system must be capable of: (i) serving forecasted electric peak demand with all HVD facilities in-service with no equipment continuous rating violations or voltage levels below established thresholds; and (ii) withstanding single elements (equipment or lines) of the HVD system being out of service during non-peak demand periods due to failure or for maintenance and construction, without loading the remaining HVD facilities beyond equipment emergency ratings or reducing voltage below established thresholds. The criteria also specify that interrupting devices must be capable of interrupting the available short circuit current.

Interrupting devices are scheduled for replacement with higher capability units when the available short circuit is projected to exceed the equipment interrupting capability.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the HVD Lines and Substations Capacity sub-program?

A. The Company is projecting HVD Lines and Substations Capacity capital expenditures of $20,203,000, as shown in Exhibit A-32 (RTB-5), line 2, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the five investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 59 below.

FIGURE 52:
HVD LINES AND SUBSTATION CAPACITY INVESTMENT CATEGORY EXPENDITURES AND PROJECTS

Investment Categories	Capital	# of Projects
Load carrying capabilities and voltage support	$2,955,000	4
New interconnections	$4,454,000	24
Improved functionality	$5,247,000	14
Coordination with Transmission	$2,429,000	4
Right of way procurement	$3,035,000	9
TBD	$2,084,000	
Total	**$20,203,000**	**55**

Q. What has been the historical actual spending in the HVD Lines and Substations Capacity sub-program for the past five calendar years?

A. The Company's historical actual spending in the HVD Lines and Substations Capacity sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 25.

Q. Please explain year-over-year variation in spending in this program.

A. In 2016, the Company completed a larger-than-normal project that included the new approximately 10-mile Arcadia-Grace Rd 46 kV line, rebuilding approximately 10 miles of the existing radial Arcadia 46 kV line, and converting approximately two miles of the existing Farr Road-Onekama 46 kV line to double circuit. This project was required to alleviate projected thermal and voltage criteria violations, providing significant reliability and loss-saving benefits. This large project, in addition to typical work levels, resulted in higher spending in that year. In 2019, the Company completed several additional larger-than-normal projects, including rebuilding approximately 3.5 miles of the 46 kV Jackman line due to projected thermal criteria violations, and rebuilding approximately seven miles of the 46 kV Upton line to coordinate with a transmission project. These large projects combined with the typical workload resulted in higher spending in 2019.

Q. What is the basis for the requested spending level for the HVD Lines and Substations Capacity sub-program in this filing?

A. The requested spending level of $20,203,000 is consistent with the amount spent in 2019, and the amount projected to be spent in 2020. The level of spending requested in this filing will enable the Company to complete (i) four load carrying capability and voltage support projects; (ii) 24 new interconnections projects; (iii) 14 improved functionality projects; (iv) four coordination with transmission projects; and (v) nine ROW procurement projects.

Q. Please list any prioritized projects that make up the requested spending level in the HVD Lines and Substations Capacity sub-program for the 2021 test year.

A. All of the identified projects are listed in Exhibit A-42 (RTB-15), page 28, line 25, through Exhibit A-42 (RTB-15), page 29, line 43. The Company has developed concept approvals in support of certain projects in this sub-program, as listed in Exhibit A-41 (RTB-14), lines 25 through 30.

Q. Why do some of the new interconnections projects in Exhibit A-42 (RTB-15) indicate negative amounts of spending?

A. Some projects in this investment category are fully paid for by the requesting customer, resulting in a net zero impact to rate base. The negative spending amounts shown in Exhibit A-42 (RTB-15) account for this. The Company will complete these projects, and subsequently be paid by the requesting customer, so there is cash flow associated with these projects.

Q. Are there any costs included in the Company's HVD Lines and Substations Capacity spending request for the 2021 test year for which specific projects have not yet been identified?

A. Yes.

Q. What is that amount?

A. $2,084,000.

Q. For this requested spending that is not tied to a listed project, please explain how the Company will identify additional projects to account for that spending.

A. The Company will identify additional project(s) later in 2020 for construction in 2021, using the planning process described above in my direct testimony. The HVD system model is updated annually following summer peak loading, continuing 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. Some projects in this sub-program accommodate requests from the transmission company;

depending on specific project details such requests for 2021 may not have been made as of the time of this filing, indicating a need for some spending to be set aside for projects that have not yet been identified.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the HVD Lines and Substations Capacity sub-program?

A. Because the HVD system is the backbone infrastructure of the electric distribution network, projects in this sub-program must be completed on an as-needed basis to serve customers and maintain the safety and overall reliability of the grid. Investments in this sub-program improve system reliability by preventing future overloads. Furthermore, these investments help avoid dangerous wire downs and equipment failures due to overloads and exceedance of equipment interrupting capability, improving system safety.

3. LVD Substations Capacity

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the LVD Substations Capacity sub-program.

A. The LVD Substations Capacity sub-program ensures the long-term safe and reliable operation of our electric distribution LVD substations. The necessary capital expenditures include investments to install new substations or substation equipment and to upgrade existing substations or substation equipment to ensure customer electric loads are served within the operating capacity of the installed substation equipment (i.e., transformers, fuses, reclosers, regulators, and switches). The LVD Substations Capacity investments are divided into two categories: (i) new substations; and (ii) existing substations capacity increases.

Q. Please describe the process and criteria to which the LVD Substations are planned.

A. LVD Substations Capacity planning activities are based on peak load conditions. Monitoring and analysis is done to identify situations where a component of the LVD substation has experienced an overload of its rated capacity. LVD substation capacity projects are prioritized to address the highest overloads in advance of lower overloads, with adjustments made for other factors such as historical reliability, customer mix, and safety impact. When assessing loads, the Company prudently considers actual and known new business load additions.

Q. When an LVD substation capacity situation is identified, what alternatives are considered for resolution?

A. Alternatives typically considered are: (i) transferring load to an adjacent and less loaded substation or line; (ii) upgrading equipment or lines to provide the needed capacity; (iii) building a new LVD substation to share the load capacity; and (iv) connecting to a different HVD source.

Q. Does the Company consider non-wires alternatives in the LVD Substations Capacity sub-program?

A. The Company has been exploring the potential for considering non-wires alternatives as LVD substation capacity solutions in recent years. In 2017 and 2018, the Company ran a pilot program to explore whether or not an anticipated capacity upgrade at the Swartz Creek substation could be deferred through the use of targeted energy efficiency and demand response, under the premise that these targeted programs could reduce peak load on the substation and defer the capacity project. In 2019, the Company began a second pilot to further explore the use of targeted energy efficiency and demand response to defer an anticipated capacity upgrade at the Four Mile substation near Grand Rapids. In going through multiple pilot iterations, the Company has refined its selection criteria for identifying potential LVD substations where non-wires alternatives can be considered, with criteria including the peak load reduction needed, the timeframe of the projected need, customer mix, and other factors. While these pilots are not administered by the Electric Planning organization, LVD engineers play a role in identifying potential LVD substations to target. As the Company continued to develop lessons learned from these pilots, the Company may become better able to consider non-wires alternatives as solutions more widely.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Substations Capacity sub-program?

A. The Company is projecting LVD Substations Capacity capital expenditures of $14,002,000, as shown in Exhibit A-32 (RTB-5), line 3, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the two investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 60 below.

FIGURE 60
LVD SUBSTATIONS CAPACITY INVESTMENT CATEGORY
EXPENDITURES AND PROJECTS

Investment Categories	Capital	# of Projects
New substations	$8,500,000	5
Existing substations capacity increase projects	$5,502,000	7
Total	**$14,002,000**	**12**

Q. What has been the historical actual spending in the LVD Substations Capacity sub-program for the past five calendar years?

A. The Company's historical actual spending in the LVD Substations Capacity sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 26.

Q. Please explain year-over-year variation in spending in this sub-program.

A. In 2015, the Company had to shift some funding away from the LVD Substations Capacity to other programs to address emergent issues. Therefore, some projects originally scheduled for 2015 were instead completed in 2016, resulting in lower spending in 2015 and higher spending in 2016 relative to average levels. Additionally, in 2016 the Company invested in a rebuild of the Ellsworth substation as an LVD Substations Capacity project, further increasing spending in that year.

Q. What is the basis for the Company's requested spending level in this sub-program?

A. The Company's projected spending for the 2021 test year for the LVD Substations Capacity sub-program is based on the Company's identified capacity needs. The level of spending requested in this filing will enable the Company to (i) build five new substations; and (ii) complete seven projects to increase existing substation capacity.

Q. Please list any prioritized projects that make up the requested spending in the LVD Substations Capacity sub-program for the 2021 test year.

A. The following new substations projects have been identified for the 2021 test year:

- Cloverleaf substation - $1,500,000;
- Huckleberry substation - $2,000,000;
- Mosel substation - $2,000,000;
- Skyline substation - $1,500,000; and

- Vipond substation - $1,500,000.

These five new substations for the 2021 test year are listed in Exhibit A-42 (RTB-15), page 29, lines 46 through 50. The following existing substation capacity increase projects have been identified for the 2021 test year:

- Bilmar substation - $1,500,000;
- Breedsville substation - $300,000;
- Eleventh Street substation - $600,000;
- Millers Point substation - $450,000;
- Tremaine substation - $225,000;
- Wealthy Street substation - $1,500,000; and
- White Cloud substation - $900,000.

These seven existing substation capacity increase projects for the 2021 test year are listed in Exhibit A-42 (RTB-15), page 29, lines 51 through 57. The Company has developed concept approvals for certain projects in this sub-program, as listed in Exhibit A-41 (RTB-14), lines 31 through 33.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Substations Capacity sub-program?

A. LVD Substations Capacity investments are necessary for the overall operation and reliability of the electric distribution system, by preventing future overloads and ensuring that the Company has adequate capacity on the distribution system to serve customer load.

4. LVD Transformers Capacity

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the LVD Transformers Capacity sub-program.

A. As discussed above when describing the LVD Transformers New Business and LVD Transformers Demand Failures sub-programs, capital investments in transformers are a single purchase plan that is allocated to three separate sub-programs based on actual historical activity. LVD Transformers Capacity accounts for approximately 7% of the projected investment. Due to the large volume of projects in this sub-program, the Company does not plan for these projects on an individual level.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD Transformers Capacity sub-program?

A. The Company is projecting LVD Transformers Capacity capital expenditures of $2,473,000, as shown in Exhibit A-32 (RTB-5), line 4, column (f).

Q. What has been the historical actual spending in the LVD Transformers Capacity sub-program for the past five calendar years?

A. The Company's historical actual spending in the LVD Transformers Capacity sub-program for the past five calendar years is shown in Exhibit A-29 (RTB-2), line 27.

Q. What is the basis for the Company's requested spending level in this sub-program?

A. There are two factors. The large increase in New Business work reduced the allocation percentages for the LVD Transformers sub-programs. The Company also had a decrease in overall capacity investment in 2019, particularly LVD Lines Capacity. The allocation percentages have shifted correspondingly, reducing the projected investment in LVD Transformers Capacity.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD Transformers Capacity sub-program?

A. Installation of new transformers for Capacity project work allows the Company to continue providing reliable service to customers within nominal acceptable quality standards.

5. LVD New Business Capacity

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the LVD New Business Capacity sub-program.

A. Equipment and lines need to be added or upgraded for new customers or to maintain adequate service to existing customers when they increase their load beyond current deliver capacity. Historically, work in this sub-program was part of the LVD Lines Capacity sub-program, but it is now being considered as a separate sub-program to reflect the customer request-driven nature of the work. Projects in the LVD New Business Capacity sub-program are generally similar in scope to projects in the LVD Lines Capacity sub-program. Because work in this sub-program is driven by customer requests, the Company does not plan or prioritize projects far in advance in this sub-program. The Company is projecting to complete between 1,000 and 1,500 projects in this sub-program in 2021, with specific projects to be identified based on customer requests.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the LVD New Business Capacity sub-program?

A. The Company is projecting LVD New Business Capacity capital expenditures of $11,777,000, as shown in Exhibit A-32 (RTB-5), line 5, column (f).

Q. What has been the historical actual spending in the LVD New Business Capacity sub-program?

A. As noted above, the LVD New Business Capacity sub-program is a newly separate sub-program, with the work previously considered as an investment category in the LVD Lines Capacity sub-program. The Company only began using separate investment categories in 2018, as part of its filing in Case No. U-20134. Therefore, spending on LVD New Business Capacity was not tracked separately prior to 2018. Given that, the historical actual spending is shown in Exhibit A-29 (RTB-2), line 28, and is as follows:

- 2018: $10,260,000; and
- 2019 (projected): $15,397,000.

As noted already, LVD New Business Capacity work was considered as an investment category in the LVD Lines Capacity sub-program prior to 2018. During the period from 2014 through 2017, the Company spent the following amounts on LVD New Business Capacity projects within the LVD Lines Capacity sub-program:

- 2014: $4,467,000;
- 2015: $5,687,000;
- 2016: $3,786,000; and
- 2017: 8,015,000.

Those spending totals are included within the LVD Lines Capacity historical spending shown in Exhibit A-29 (RTB-2), line 24, columns (c) through (f).

Q. What is the basis for the requested spending level for the LVD New Business Capacity sub-program in this filing?

A. Because LVD New Business Capacity work is based on emergent, customer-driven needs, the Company bases its spending projections on historical actual spending with adjustments for observed trends. The Company has been experiencing a steady increase in spending on LVD New Business Capacity in recent years. The Company anticipates that the sharp spending increase in 2019 will not be sustained going forward; some of the 2019 increase was driven by new cannabis growing operations in response to recent changes in Michigan law, and the Company does not expect this growth to continue at such a rapid rate.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the LVD New Business Capacity sub-program?

A. As with other Capacity sub-programs, work in the LVD New Business Capacity sub-program ensures the reliable distribution of electricity to customers by preventing overloads on the system. The LVD New Business Capacity sub-program provides the added benefit of allowing customers, particularly in the commercial and industrial sectors, to expand their activities and drive economic growth in Michigan.

6. Conservation Voltage Reduction

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the CVR sub-program.

A. CVR, a key component of the Company's Grid Modernization strategy, is the capability to optimize service-point, or customer meter, voltages to reduce energy demand without requiring active participation or behind-the-meter investment by customers. CVR uses a set of technologies, including VVO, that reduces the delivery voltage along LVD circuits, thereby reducing the amount of electric load that must be served on the LVD circuit, and thus, on the electric system. The technology works together and optimizes control settings on both substation and downstream voltage regulating equipment. The technology allows for continuous monitoring and automatic adjustment of these settings to achieve optimal voltage and load reduction while staying within the regulatory requirements. CVR was also part of the Company's 2018 IRP in Case No. U-20165, which was approved by the Commission in 2019. In this filing, the Company has created this new sub-program in the Capacity Program to complete capital projects necessary for implementing the Company's overall CVR plan that was included in the 2018 IRP.

Q. What is included in these necessary capital projects?

A. The purpose of these projects is to conduct circuit conditioning and upgrades to ensure that the targeted LVD circuits can enable CVR without providing voltage to customers outside the allowable range. These projects include installing DSCADA, regulator controllers, and capacitor controllers on targeted circuits. These projects also include work to address potential voltage issues. The Company will use Advanced Metering Infrastructure ("AMI") data to determine voltage levels being provided to customers; if a customer's existing voltage is outside the range that would allow CVR optimization, the Company will complete transformer upgrades and/or line reconductoring to improve the voltage.

Q. Are there any other capital expenditures under this sub-program?

A. Spending in this sub-program will also include capital labor costs for a dedicated CVR engineer and a CVR technician, plus part-time SCADA support labor.

Q. How will 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 own meter data provides sufficient telemetry to ensure continuous measurement and verification of CVR performance.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the CVR sub-program?

A. The Company is projecting CVR capital expenditures of $2,851,000, as shown in Exhibit A-32 (RTB-5), line 6, column (f).

Q. What has been the historical actual spending in the CVR sub-program?

A. As shown in Exhibit A-29 (RTB-2), line 29, this sub-program was new in the 2020 bridge year. In that year, the Company is projecting to spend $2,737,000.

Q. What is the basis of the projected spending level in this sub-program?

A. Spending in this sub-program is designed to implement the Company's CVR plan, as originally proposed and approved in Case No. U-20165. In the Company's multi-year CVR deployment plan, the Company is enabling CVR on 65 circuits in 2020 and on 75 circuits in 2021. The 75 planned circuits for the 2021 test year are listed in Exhibit A-42 (RTB-15), page 30.

Q. Has the Commission pre-approved recovery of any of the Company's CVR expenditures?

A. Yes. Pursuant to the terms of the settlement agreement approved by the Commission in Case No. U-20165, CVR-related capital expenditures of $8,924,600 over the three years of June 2019 through June 2022 were deemed to be "reasonable and prudent and pre-approved for cost recovery purposes." The 2020 bridge year and 2021 test year spending amounts for the CVR sub-program are part of this pre-approved $8,924,600 amount.

Q. Is the Company's CVR deployment plan still the same as outlined in Case No. U-20165?

A. No. The beginning of the deployment plan was delayed from 2018 to 2019. In order to complete deployment by 2028, as proposed in Case No. U-20165, the Company has revised its deployment plan through 2021, as shown in Figure 61 below.

FIGURE 61
REVISED CVR DEPLOYMENT PLAN

Year	2018	2019	2020	2021	2022+
New CVR Circuits – Case No. U-20165	20	30	50	50	50/year
New CVR Circuits – Updated Plan	0	10	65	75	50/year

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the CVR sub-program?

A. The benefits of CVR were discussed in the Grid Modernization Strategy section of my direct testimony and were discussed in the Company's IRP filing in Case No. U-20165. The Company is forecasting that CVR will provide energy and demand savings, as well as loss reduction, as shown in Figure 62 below. As the Company continues its initial testing, as described above, forecasts may be refined.

FIGURE 532
CVR CUMULATIVE ENERGY AND DEMAND SAVINGS

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Cumulative Peak MW Reduction	2	17	33	44	56	67	78	89	100	111
Cumulative MWh Reduction	4,968	37,618	75,520	101,054	126,683	152,513	178,251	204,253	230,375	256,733
Cumulative MWh Loss Reduction	174	1,317	2,644	3,5338	4,435	5,339	6,240	7,150	8,064	8,937

7. <u>HVD Lines Interconnections</u>

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the HVD Lines Interconnections sub-program.

A. HVD Lines Interconnections is a new sub-program in the 2021 test year. This sub-program funds HVD lines work necessary to interconnect Company-owned solar generation that is being built as part of the Company's 2018 IRP. The Company anticipates identifying specific locations that it will install this solar generation later in 2020. The Company's projected spending level in this sub-program is based on the amount of Company-owned solar generation that was identified in the Company's proposed course of action in the 2018 IRP.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the HVD Lines Interconnections sub-program?

A. The Company is projecting HVD Lines Interconnections capital expenditures of $2,062,000, as shown in Exhibit A-32 (RTB-5), line 8, column (f).

Q. What has been the historical actual spending in the HVD Lines Interconnections sub-program?

A. Because this sub-program is new in the 2021 test year, there is no historical spending.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the HVD Lines Interconnections sub-program?

A. The Company's 2018 IRP included significant investments in future years in Company-owned solar generation to ensure continued reliable supply of electricity for customers as coal-fired generation is retired and carbon emissions are reduced. The work in the HVD Lines Interconnections sub-program is essential in bringing that new solar generation on to the grid.

8. <u>HVD Substations Interconnections</u>

Q. Please explain what projects, activities, and other types of work will be funded by expenditures in the HVD Substations Interconnections sub-program.

A. HVD Substations Interconnections is a new sub-program in the 2021 test year. This sub-program funds HVD substation work necessary to accommodate interconnection of Company-owned solar generation that is being built as part of the Company's 2018 IRP. The Company anticipates identifying specific locations that it will install this solar generation later in 2020. The Company's projected spending level in this sub-program is based on the amount of Company-owned solar generation that was identified in the Company's proposed course of action in the 2018 IRP.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the HVD Substations Interconnections sub-program?

A. The Company is projecting HVD Substations Interconnections capital expenditures of $1,634,000, as shown in Exhibit A-32 (RTB-5), line 10, column (f).

Q. What has been the historical actual spending in the HVD Substations Interconnections sub-program?

A. Because this sub-program is new in the 2021 test year, there is no historical spending.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the HVD Substations Interconnections sub-program?

A. The Company's 2018 IRP included significant investments in future years in Company-owned solar generation to ensure continued reliable supply of electricity for customers as coal-fired generation is retired and carbon emissions are reduced. The work in the HVD Substations Interconnections sub-program is essential in bringing that new solar generation on to the grid.

E. "Electric Other" Program

Q. What is included in the Electric Other Program?

A. The Electric Other Program includes the following sub-programs in the 2021 test year: (i) Computers and Equipment; (ii) Tools; (iii) System Control Projects; and (iv) Grid Technologies. Spending in Grid Technologies directly supports the Company's Grid Modernization strategy and was explained earlier in my direct testimony.

Q. What is the Company's total projected investment in the Electric Other Program in this case, and what is the basis for this level of investment?

A. As shown in Exhibit A-35 (RTB-8), line 8, column (c), the Company's 2019 Electric Other Program spending was projected to be $7,540,000. This 2019 spending level is higher than recent historical years, primarily due to an increase in spending in the Tools sub-program, which I discuss below. Electric Other Program spending increases in the 2020 bridge year, when the Company is projecting $9,813,000 in total Electric Other spending, as shown in Exhibit A-35 (RTB-8), line 8, column (d). This increase is due primarily to an increase in spending on System Control Projects, which I also discuss below. For the 2021 test year, the Company projects to spend $11,412,000, as shown in Exhibit A-35 (RTB-8), line 8, column (f). Projected 2021 spending is explained in greater detail in the Capacity sub-program sections below; much of the year-over-year program increase from 2020 to 2021 is due to the addition of the grid technologies project, which I discussed earlier in my direct testimony.

1. 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 Computer and Equipment sub-program consists of the capital costs to purchase and replenish computer equipment for electric distribution purposes. The Company is projecting 2021 test year capital expenditures in this sub-program of $100,000, as shown in Exhibit A-35 (RTB-8), line 1, column (f). As shown in Exhibit A-29 (RTB-2), line 48, column (h), this amount is lower than spending for this sub-program in 2014, 2015, and 2017 and is moderately higher than spending for this sub-program in 2016 and 2018.

2. 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 tools and replacement of tools 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;
- Silica mitigation systems;
- Calibrated tools;
- Test meters/instruments;
- Diagnostic or locating equipment;
- Line segmenting (load drop/load pickup) devices;
- Wire pulling machines/accessories; and
- Specialty rigging, work lighting, pumping, or "bridging" and "matting" equipment.

Since 2016, this sub-program also includes outfitting new Company trucks (service bucket trucks, two-person buckets, and digger derricks) with truck tool packages, standard packages of essential tools to ensure that crews go into the field with appropriate equipment. The purchase plan for these truck tool packages is based on the Company's fleet acquisition and deployment plan.

Q. Why is the purchase of these tools necessary?

A. The purchase of the tools covered in this sub-program is necessary to improve electric reliability, reduce risk of employee safety incidents and injuries, and improve employee productivity by having the proper tools available. Without these tools, the Company would not be able to perform routine compliance and maintenance work for customers.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the Tools sub-program?

A. The Company is projecting Tools capital expenditures of $5,792,000, as shown in Exhibit A-35 (RTB-8), line 2, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated between investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 63 below.

FIGURE 54
TOOLS INVESTMENT CATEGORY
EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
Truck tool packages	$2,118,000	60
Other capital tool purchases	$3,674,000	N/A
Total	**$5,792,000**	

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 Exhibit A-29 (RTB-2), line 49.

Q. Please explain year-over-year variation in spending in this sub-program.

A. Spending in this sub-program has been increasing for two primary reasons. First, the Company has been purchasing truck tool packages since 2016. Second, spending on general capital tools has increased as tool prices have increased, as more tools have reached the end of their useful life and must be replaced, and as the Company has invested in newer types of tools to improve safety. In particular, the Company has invested in more ergonomic tools to reduce the risk of employee injury; the corresponding reduction in injuries provides savings for the Company, since injuries are typically far more expensive than tool purchases. The Company has also invested in high-visibility tools to ensure that crews are more visible to motorists and the public in general.

Q. What is the basis for the Company's projected spending level in this sub-program?

A. In the 2021 test year, the Company will continue with its process of purchasing truck tool packages for new Company trucks, with 60 truck tool packages purchased in 2021 in line with the Company's fleet acquisition and deployment plan. Since the Company only began making these purchases in 2016, prior years would not have included this spending. As shown in Exhibit A-35 (RTB-8), line 2, columns (b) through (d), the Company's spending in this sub-program has increased from $3,822,000 in 2018, to $5,521,000 in 2019, to $5,691,000 in 2020, indicating that the level of spending projected for 2021 is aligned with a new higher level of spending that accounts for the truck tool packages. Additionally, spending on overall capital tools has increased from the historical period, as discussed above, although this has leveled off since 2019.

Q. How is the spending on other capital tools besides the truck tool packages broken down?

A. As stated above, this sub-program covers a wide variety of potential tool replacements in cases where tools are priced at over $1,000. The Company does project spending for certain specific kinds of tools, as shown in Figure 64 below.

FIGURE 554
2021 CAPITAL TOOLS SPENDING BREAKDOWN

Investment Categories	**Capital**
General capital tools	$2,733,000
Live line tool testing	$360,000
Fire-retardant clothing	$325,000
Electric tool calibration	$97,000
Tool crib stock	$75,000
Electric rigging equipment	$39,000
Remote spiker tool	$25,000
Cable phasers	$20,000
Total	**$3,674,000**

Tool cribs allow the Company to better manage the quick replacement of tools; they facilitate availability of spare tools in easily accessed locations, so crews with damaged or defective tools can quickly return to the field. Live line tool testing and tool calibration are required by OSHA to ensure employee safety. Cable phasers and remote spiker tools are also essential for employee safety, as they are critical for ensuring that crews work on the correct conductors.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the Tools sub-program?

A. Company crews require appropriate tools and equipment when in the field, both to ensure their own safety and the safety of the public, and to be able to complete their work in an expeditious manner to reduce outage times. Spending in this sub-program ensures that tools are replaced in a timely manner once they are no longer useful, and that Company trucks have appropriate tools with them at all times.

3. 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. System Control Projects are divided into four investment categories in this filing: (i) HVD operations projects; (ii) HVD remote monitoring and control capabilities projects; (iii) operating technology enhancements; and (iv) System Control Center ("SCC") and DCC control room modifications.

Q. What is included in HVD operations projects?

A. HVD operations projects include installation and conversion of switches to isolate faults and minimize customer interruptions, with locations identified by the Company's System Operations Engineering personnel. The locations of some switching devices on the HVD system makes it difficult to isolate areas where a fault has occurred, increasing the number of customers interrupted, and the duration of interruptions, while repairs take place. Projects in this investment category add automation to existing switches at these locations by converting them to MOABS, and add new switches with MOABS, reducing outage durations and isolating faults to smaller line segments with fewer customers. For example, it is possible for an outage on a HVD line section, which feeds multiple LVD substations, to interrupt service to 10,000 or more customers until repairs are completed. If an additional HVD switch is installed in this same line section, the number of customers experiencing the outage may be reduced to 5,000 customers via the use of the additional switch to sectionalize the affected HVD line.

Q. What is included in HVD remote monitoring and control capabilities projects?

A. These projects improve operational visibility in the SCC and DCC, and will ultimately enable remote monitoring and control of some MOABS via line sensors and the SCADA system. When these line sensors and SCADA are fully deployed, operators will have the ability to remotely monitor and operate all of these switches, providing them with key, real time information on the status (open or closed) of MOABS on our system. Operators can use this information to make operational adjustments to the HVD system when possible, keeping the HVD system in an optimal state. Through 2020, this investment category is a Grid Modernization pilot program, but beginning in the 2021 test year it will become an investment category that is fully funded in the System Control Projects sub-program.

Q. What is included in operating technology enhancements?

A. Operating technology enhancements improve functionality and operations of the SCC in Jackson, the DCC in Grand Rapids, and Work Management Centers ("WMCs") in Jackson, Grand Rapids, and Saginaw. Specific enhancements vary from year to year. In the 2021 test year, the enhancements are as follows:

- **WMC upgrades for storm teams**: adding technology for storm restoration management;
- **Wire down/damage assessment mobile applications**: used by field crews to report real time field conditions, which will also make employee locations clear at all times;
- **Badge scan check-in for storm response**: to eliminate the need for a check-in/check-out specialist role. Similar tools are used in other emergency response applications, such as by fire departments; and
- **New Transmission Outage Application functionality**: to integrate this outage planning software with the Company's SAP and mobile systems, streamlining

operations and improving safety by allowing all employees to be up-to-date on equipment that is energized and deenergized during outage response.

Q. What is included in SCC and DCC control room modifications?

A. The purpose of these modifications is to provide sufficient working space for SCC and DCC personnel as the SCC and DCC take on increased responsibilities; as the Company deploys ADMS, the SCC and DCC require additional space for computers and personnel. In particular, additional distribution operations engineers will be needed.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the System Control Projects sub-program?

A. The Company is projecting 2021 test year capital expenditures of $4,170,000, as shown in Exhibit A-35 (RTB-8), line 3, column (f).

Q. Please explain how the capital expenditures projected for the test year for this sub-program will be allocated across the four investment categories.

A. The Company is projecting unit and capital expenditures in the test year for each investment category as identified in Figure 65 below.

FIGURE 565
SYSTEM CONTROL PROJECTS INVESTMENT CATEGORY
EXPENDITURES AND UNITS

Investment Categories	Capital	# of Units
HVD operations projects	$994,000	1
HVD remote monitoring and control capabilities	$2,305,000	62
Operating technology enhancements	$795,000	4
SCC and DCC control room modifications	$77,000	N/A
Total	**$4,170,000**	

Q. What has been the historical actual spending in the System Control Projects sub-program for the past five calendar years?

A. The Company's historical actual spending is shown in Exhibit A-29 (RTB-2), line 50.

Q. Please explain year-over-year variation in spending in this sub-program.

A. Relatively little spending occurred in this sub-program prior to 2017. However, the Company consistently and continually explores opportunities to improve the performance and operability of the distribution system, with such opportunities typically coming in the form of expanding known solutions and applying current technology to other parts of the system, or in introducing new technologies. As system conditions have evolved over the years, new projects with positive benefits were identified and included in the Company's plans. For example, while the Company has utilized SCADA for many years at HVD substations, expanding SCADA to MOABS on HVD lines was found to improve monitoring and operating capabilities on the HVD lines. Newfound opportunities such as these drove new spending in 2018 and 2019 and will continue to drive spending in 2020 and beyond.

Q. What is the basis of the Company's requested spending level for System Control Projects in this filing?

A. As noted above, spending has been increasing in this sub-program as the Company identifies new opportunities to implement new technologies to improve system performance. As the HVD remote monitoring and control capabilities investment category becomes part of this sub-program in 2021, spending is increasing. The projected 2021 spending level in the HVD remote monitoring and control capabilities investment category is based on the Company's estimate that it will install 50 three-phase line sensors, costing $10,000 each; and 12 SCADA switches, costing $150,000 each.

Q. Please list any prioritized projects that make up the requested spending level in the System Control Projects sub-program for the 2021 test year.

A. In 2021, the Company plans to rebuild 0.78 miles of the Hughes Road 46 kV line as an HVD operations project, to add MOABS capabilities. The Company is also planning the four operating technology enhancement projects described above. The Company will prioritize circuits for HVD remote monitoring and control capabilities projects for the 2021 test year in the first quarter of 2020.

Q. What benefits will customers realize through the Company completing work, at the requested spending level, in the System Control Projects sub-program?

A. As discussed above, improving monitoring and control capabilities on the distribution system helps streamline operations and reduce the impact of any single fault, reducing interruptions for customers. The technology enhancements and control room modifications will better enable employees to provide safe and reliable electricity.

VII. TECHNOLOGY PROJECTS SUPPORTING ELECTRIC DISTRIBUTION

Q. Is the Company planning technology projects in the 2021 test year that support the Company's electric distribution strategy?

A. Yes. Company witness Jeffrey D. Tolonen is sponsoring several technology projects critically important to the Company's electric distribution strategy. They are as follows:

- Electric Underground Conflation;
- Field Contractor Work Management Technology;
- GIS Integrated Design;

- Grid Modernization GIS Connectivity Model Integration;
- Electric Grid Telecom Device Management;
- One-Call Ticket Risk Analysis Model for Damage Prevention;
- Work Management Scheduling Analytics and Reporting;
- Electric Agricultural Services Database;
- Field Mapping and Graphics;
- Electric Infrastructure Attachments;
- Real-Time Electric System Access in the Field;
- Electric Distribution Asset Management; and
- Replacement of Testing Software for Electric Meter Technology Center ("MTC").

Company witness Tolonen provides the projected test year capital and O&M spending for each of these projects.

Q. Please explain the Electric Underground Conflation project.

A. This project will establish a single GIS repository for underground electric distribution assets through conversion of Computer Aided Design ("CAD") asset record files to assets in the electric GIS database and align the facility map records to aerial imagery and the GIS street and ROW maps ("land base"). This conversion and alignment process is referred to as conflation.

Q. What benefits will this project provide?

A. Implementation will benefit the Company through: (i) increased accuracy of system planning and analysis models; (ii) enhanced safety by providing a single, spatially accurate view for overhead and underground electric assets rather than multiple applications; (iii) a framework for the conversion of underground electric services from Service Information

Management System ("SIMS"); (iv) improved GIS integrated design quality for electric underground assets through a consolidated view of electric assets that eliminates additional manual work-arounds to manipulate designs to align overhead and underground electric digital records; (v) improved productivity for electric designers, dispatchers, schedulers, and all office electric GIS users by eliminating additional manual work-arounds necessary to match the electric underground distribution records with the previously conflated land base; vi) improved safety for field operations by providing a spatially accurate representation of electric distribution assets over the previously conflated land base files, eliminating the misalignment and risk of misinterpretation of asset location between the conflated land base and un-conflated electric distribution files; (vii) improved damage prevention through better analysis for MISS DIG staking by providing a broader view of the electric underground system; and (viii) improved safety and reliability during storm restoration activities through enhancement of the outage management system mapping application via inclusion of a more detailed underground electric asset location view that provides dispatchers with more accurate data when locating faults and improves switching operations.

Q. What is the scope and cost for this project?

A. The project scope includes: (i) conversion of electric underground distribution assets currently stored in CAD file format to the electric GIS database; (ii) conflation of electric underground data to spatially align to the GIS land base; (iii) enhancing the electric GIS data model to support an enhanced system model; (iv) establishing data quality assessment and quality control of electric underground distribution data; and (v) configuring the

Primary Distribution Map ("PDM") print-to-PDF solution. As stated by Company witness Tolonen, this project includes capital costs of $392,000 and O&M costs of $11,000.

Q. What alternatives did the Company consider for this project?

A. Alternatives considered include: (i) delaying implementation; and (ii) providing conversion services by skilling up internal resources. Delaying implementation was not chosen because this work is foundational to other GIS-based electric technology projects, including the conversion of electric service records to GIS. Delaying the conflation project will then delay the electric service conversion, which prolongs the maintenance of the legacy system, and does not mitigate the safety risk inherent in maintaining service records in two systems. Completing the conversion with internal resources was not chosen because of the significant cost needed to skill up internal resources to complete "one time" nature of work. The alternative to outsource the conversion and conflation was selected because it is the most cost-effective and efficient solution.

Q. Please explain the Field Contractor Work Management Technology project.

A. This project will provide the ability to electronically manage contractor work, increasing accuracy and timeliness of information processing for field work deliverables. This project will create new opportunities to measure and optimize field work processes that support customer on-time delivery goals.

Q. What benefits will this project provide?

A. The project will add value by: (i) improving on-time delivery of customer work by providing electronic work order information to contractors; (ii) improving customer satisfaction through efficiency in scheduling work and reporting on the progress electronically; (iii) increasing safety by tracking work and contractor status; (iv) improving material management; (v) making it easier to move emergent work to contractors, which will better meet customer commitments and balance workload; and (vi) enabling real time updates to work order information, increasing data accuracy and reducing invoice reconciliation time.

Q. What is the scope and cost of this project?

A. The project scope includes: (i) meeting with stakeholders to identify requirements for a Bring Your Own Device ("BYOD") field contractor work management technology solution and process; (ii) developing, configuring, and testing interfaces, hardware, and software for the solution; (iii) implementing the solution and process for the following work groups: Electric HVD, Electric LVD, Mutual Assistance, Forestry, Gas Distribution, Gas Code Compliance, and Substation Operations Construction/Metro; (iv) updating the following vendor contract types to support BYOD field contractor work management: zone, specific bid, ancillary, electric storm, and mutual assistance; and (v) training field contractors on new technology and processes. As stated by Company witness Tolonen, this project includes $1,937,715 in capital costs and $171,680 in O&M costs.

Q. What alternatives did the Company consider?

A. The alternatives considered included: (i) continuing with the current paper-based process; (ii) using the current Company mobile application; (iii) using off-platform options such as Service Bench; and (iv) providing Company-funded field devices to get contractors on a common technology platform. These alternatives were not chosen because, respectively: (i) this approach does not allow for the timely, data-driven work management metrics required to improve servie to customers; (ii) this solution is not expected to receive long term investment by the vendor and the mobile application would require more upfront investment than the proposed option; (iii) to ensure contractors leverage the benefits and integrations with the existing Service Suite platform, the chosen option is preferred; and (iv) the investment in hardware, management of on-boarding and off-boarding of devices to contractors, and training and change management is cost-prohibitive and introduces risk of loss of control of information security and corporate assets. The ABB Service Suite hybrid solution was chosen because it uses existing well-developed Service Suite functionality while leveraging cloud-based, BYOD capability to move short-term and long-term contractors from paper processes to the established, standard work management system.

Q. Please explain the GIS Integrated Design project.

A. This project replaces the CAD and Work Requirements and Design software with Bentley's Open Utilities Map ("BOUM") to leverage GIS asset data to generate engineering designs, implement workflows with SAP, and mitigate risk associated with the aging software application.

Q. What benefits does this project provide?

A. The project provides value to the Company in three ways: (i) the BOUM software is compatible with GIS integration and may be further developed after the Company implements the UPDM as the basis of its GIS systems; (ii) the project mitigates risk of manual asset record imports, asset record manipulation for design white space management, or manual asset record recreation for base design files, by enabling technology that creates a new design over existing electronic asset records; (iii) it enables technology that is compatible with the asset system of record and the Project Wise engineering document management system.

Q. What is the scope and cost of this project?

A. The project scope includes: (i) replacing CAD engineering design software (Bentley Microstation J/v7) with BOUM; (ii) leveraging GIS asset data for the purpose of generating engineering designs; (iii) integrating workflows with SAP through Bentley Workflow Manager software; (iv) implementing GIS replication databases to isolate data editing from data viewing; (v) replacing the desktop View Graphics custom application with a web-based application for searching and viewing asset records; and (vi) implementing a Primary Distribution Map ("PDM") generation service to generate electric PDM files for printing during storm and other emergency events. As stated by Company witness Tolonen, this project includes $349,206 in O&M costs.

Q. What alternatives did the Company consider?

A. Two alternatives were considered for this project: (i) replace the application with an iTron design application, though after further review and complications in implementing an iTron solution, this alternative was not selected; and (ii) remain on the aging application. This second alternative is not viable given the lack of vendor support, technology obsolescence, inability to maintain critical operating system patching and upgrade compatibility without additional risk, and increasing maintenance expenses. After a competitive bid process the option to replace the application with BOUM was selected as the best solution to meet the Company's requirements.

Q. Please explain the Grid Modernization GIS Connectivity Model Integration project.

A. This project will design, develop, and implement a GIS extract using an industry standard to publish electric GIS data to the network, where it can be consumed by multiple applications. The extract will make the data available to the electric distribution historian as well as other applications in the future.

Q. What benefits will this project provide?

A. The project provides value to the Company by: (i) leveraging the International Electrotechnical Commission ("IEC") Common Information Model ("CIM"), which provides a basic ontology for data and data relationships and a standard repeatable approach that can be leveraged for sharing data about the electrical network across technical systems; (ii) supporting an enterprise application integration framework, which keeps business processes as simple as possible; (iii) providing the ability to detect the physical location of metered assets, including circuit, substations, and transformers; and (v) reducing the costs and time required to develop integrations in the future resulting from streamlined approaches and processes.

Q. What is in the scope and cost of this project?

A. Deliverables within the project scope include: (i) develop and implement the GIS extract, leveraging IEC CIM for data sharing; (ii) leverage the enterprise service bus as the high level communications protocol for sharing CIM data across the enterprise; (iii) build the integration to the electric distribution historian; and (iv) develop a data and integration framework that can be leveraged for future projects. As stated by Company witness Tolonen, this project includes $25,000 in O&M costs.

Q. What alternatives did the Company consider?

A. The alternative considered was to continue to implement point-to-point application-specific integrations to meet the requirements specific to a single project. This alternative was not chosen because it continues to increase the technical debt associated with the maintenance of non-standard interfaces. The preferred approach, as outlined in this business case, will result in: (i) standard, repeatable approaches for future integrations; (ii) lower ongoing maintenance costs; and (iii) less complexity.

Q. Please explain the Electric Grid Telecom Device Management project.

A. This project will implement a solution for managing the telecommunications device component of Grid Modernization that includes managing device metadata and the ability to historically manage the real-time status of telecommunications devices.

Q. What benefits will this project provide?

A. Completion of this project will benefit the Company by: (i) reducing hours spent combining data from several platforms; (ii) providing visibility into devices on the electric distribution system, including a consolidated view of multiple device types; (iii) providing highly reliable communications to field control devices in support of advanced grid functionality; and (iv) improving the ability to troubleshoot and perform root cause analysis, leading to improved reliability and a reduction in dispatching field crews for troubleshooting devices. The implementation of a communications management system that can monitor and maintain multiple wide area network/field area network device types also adds value by consolidating data from multiple disparate systems into a central repository which can then be used to manage and analyze the disposition and features of distribution grid telecommunications devices. Additionally, a platform that enables both GIS integration of asset location and telecommunication asset inventory for future substation communication needs will enable geo-based trouble analysis and proactive replacement of similar types of faulty communication equipment.

Q. What is the scope and cost of this project?

A. The scope of the project consists of: (i) implementing a communications device management solution; (ii) performing necessary data transformations; (iii) developing analytic queries that leverage the cross-functional data; (iv) defining an end-to-end business process that will support actionable findings; and (v) managing associated organizational changes. As stated by Company witness Tolonen, this project includes $91,000 in capital costs and $146,600 in O&M costs.

Q. What alternatives did the Company consider?

A. Several alternatives were considered for the execution of the project: (i) no change, which assumes the risk of failure of services for reliability and system optimization; (ii) develop an in-house application consolidating device information from vendor-specific systems into a single view; and (iii) deploy a commercial solution (cloud based or on site) that will consolidate and normalize vendor-specific data. Both alternatives two and three will be evaluated in the project planning phase to determine the most cost-effective solution, as they both support achievement of the investment objectives.

Q. Please explain the One-Call Ticket Risk Analysis Model for Damage Prevention project.

A. This project implements a risk analysis and data analytics program that identifies the riskiest excavation tickets, utilizing current one-call ticket data, damage history, and incorporating asset information from the GIS to focus damage prevention resources and activities on locate requests with the highest risk.

Q. What benefits will this project provide?

A. Completion of this project will provide value to both the Company and its customers by providing safety improvements and risk mitigation through: (i) implementation of automated screening daily one-call tickets to enable decisions that mitigate damages and support proactive communication; (ii) creation of a risk analysis model to identify and prioritize the highest risk tickets; (iii) creation of detailed data analytics for high risk tickets and actual damages to identify root cause or systemic issues; (iv) mitigation of damage prevention risk and prevented damages, which results in fewer root cause investigations, facility repairs, lost service to customers, collection efforts, legal expenses, regulatory reporting, and results in better public relations. Fewer damages result in reduced potential for serious injuries and property damage for customers. The customer directly and indirectly benefits from this implementation by reducing disruptions to service, reducing planned work interruptions for emergent work, and reducing public safety risk through proactive damage prevention measures. Improved business process, risk analysis, and monitoring, together with proactive communication about safe digging practices with highest risk excavators, will reduce damages.

Q. What is the scope and cost of this project?

A. The project scope includes: (i) vendor application hosting, maintenance, and support of one or more instances of the Cloud-based platform; (ii) a solution to provide gas and electric asset information from the GIS databases for use within the vendor platform as either extracts (file transfer protocol or emailed files) on a regular interval (i.e., quarterly, monthly) or through integration with the GIS platform; (iii) ongoing and historical ticket locate data to vendor software through either an email format, web service, or integration;

(iv) copies of ongoing and historical excavation damage records that occurred on any of the locate requests provided above by either a spreadsheet or web service; and (v) a damage risk statistical model that calculates risk scores based on multiple factors to produce outputs of a daily summary of highest risk tickets, reports, and web access to the customer portal for detailed risk assessment data. As stated by Company witness Tolonen, this project includes $580,220 in capital costs and $125,202 in O&M costs.

Q. What alternatives did the Company consider?

A. Alternatives considered include: (i) augmenting existing damage prevention staff to manually perform daily risk analysis on one-call tickets; (ii) developing an in-house, custom solution with significant consulting; and (iii) deferring risk model implementation to a future year. The first alternative was not selected because it would require a significant increase in resources to perform the work. The second alternative was not selected because the estimated capital investment would exceed a commercial vendor solution. The third alternative was not selected because it continues to defer value realization and does not provide a timely response to mitigate safety risk. The option of implementing a cloud-based solution was chosen because it implements a solution that has been tested in the industry with success, provides an ongoing support model through a subscription-based application, and provides a path to deliver faster business value through damage reductions.

Q. Please explain the Work Management Scheduling Analytics and Reporting project.

A. This project will implement a solution capable of scheduling long cycle, maintenance, and emergent work. This will combine data from the several Excel spreadsheets that are used today to allow single views of all the information needed to effectively produce the various schedules and provide reporting.

Q. What benefits will this project provide?

A. The project will add value by providing: (i) accurate schedules tied to productivity, reducing waste, and shrinking the work backlog across work types; (ii) enhanced quality and integrity of scheduling process through reduction in manual scheduling steps and hours spent developing route sheets; (iii) time saved from manual entry to be reallocated to better schedule analysis and alignment across disciplines, decreasing risk of missing code work and being in non-compliance; (iv) improved transparency into whether the weekly schedule is meeting business objectives such as financial scenarios, compliance requirements, and first time completion; and (v) increased employee engagement by having a quality product to schedule, while being able to focus on priority and execution of work versus workarounds to meet daily scheduling needs.

Q. What is the scope and cost of this project?

A. The project scope includes: (i) implementing a streamlined scheduling process across Operations; and (ii) implementing associated analytics and reporting. As stated by Company witness Tolonen, this project includes $966,348 in capital costs and $149,176 in O&M costs.

Q. What alternatives did the Company consider?

A. Two alternatives were considered for this project: (i) purchase disconnected software products; and (ii) automating manual data movement across systems through Robotic Process Automation. Option one was not chosen due to a risk of increased costs, as well as that it would include software providing overlapping functions with existing solutions or not meeting base requirements. The second option was not chosen because it will not meet base requirements and does not provide desired insights. The option to purchase the

SAP Multi Resource Scheduling module was selected as it will minimize ongoing support costs, meets base requirements, and will provide increased transparency into scheduling.

Q. Please explain the Electric Agricultural Services Database project.

A. This project will update and stabilize the system with which data for the Agricultural ("Ag") Services Neutral Separation Program is managed. The Neutral Separation Program tracks and manages mandatory inspections for stray voltage at agricultural locations.

Q. What benefits will this project provide?

A. Upgrading the Ag Services Database will provide value for both the Company and its customers by: (i) supporting consistent tracking of the agricultural services inspection program; (ii) eliminating the need for processing paper forms which reduces rework and paper waste; and (iii) maintaining up-to-date information on customers in the program, which ensures currency of participant data.

Q. What is the scope and cost of this project?

A. The scope of this project will: (i) replace the existing database with one that is supported by IT; (ii) integrate with SAP to provide access to customer information; and (iii) integrate with GIS to capture customer geographic information, including details related to connectivity, voltage, service type, management headquarters, and circuit and location. As stated by Company witness Tolonen, this project includes $292,000 in capital costs and $32,850 in O&M costs.

Q. What alternatives did the Company consider?

A. Two alternatives were considered for execution of this project: (i) build a new database that uses current technology supported by the Company and includes functionality for keeping records up to date; or (ii) restore the inoperative functionality and update the current access database. Alternative two was not chosen because the current solution uses outdated and unsupported technology, and it would not be cost-effective to maintain it. Alternative one was chosen because it will leverage current, supported database technology.

Q. Please explain the Field Mapping and Graphics project.

A. This project will implement a replacement system for the Company's mobile field mapping and data collection software that can search and view facility map data, view work order designs, and create work order as-built construction drawings in the field. This will make it possible to consolidate field graphics functionality into an efficient process while implementing a current and supported application and retiring the unsupported ArcPad solution.

Q. What benefits will this project provide?

A. The project will add value by: (i) providing more accurate geospatial data, including facility map data, pre-construction designs, and as-built construction drawings; (ii) consolidating daily tasks into a more simplified process; (iii) eliminating the process waste from duplicating asset data in two systems resulting from current system limitations; (iv) enabling the adoption of the GIS standard; and (v) allowing for growth of functionality and capabilities to make more mapping and graphics data available on field devices.

Q. What is the scope and cost of this project?

A. The project scope includes: (i) installing a new mobile field mapping and graphics application; (ii) creating the ability to search and view the facility map data in GIS format, and the ability to search by address; (iii) producing the ability to view pre-construction work order designs in a new GIS format; and (iv) enabling the creation of as-built construction drawings in GIS format for assigned work orders. As stated by Company witness Tolonen, this project includes $1,428,719 in capital costs and $23,852 in O&M costs.

Q. What alternatives did the Company consider?

A. Three alternatives were explored and determined non-viable for the project:

(i) Continue to maintain the current ArcPad application. This option was not selected because the Company is no longer able to make changes to the ArcPad application to mitigate issues if the application has critical defects. A total failure of the application could revert field crews back to paper-based facility maps, risking safety through the use of static, oudated data; or require the creation of as-built construction drawings on paper documents;

(ii) Use the existing Mobile Information Management System ("MIMS") mapping solution for facility maps portion and use other existing applications that have rudimentary drawing capabilities, like Adobe or Snagit, for creating as-built construction drawings. This option was not selected because it would introduce significant cost because of the complexity and customization to integrate the applications. Also, this alternative would forfeit the already-established user experience and application integration achieved with the proposed MIMS solution; and

(iii) Rebuild ArcPad from the ground up. This option was not selected as existing industry solutions are available at a much lower cost with much less risk. Implementing the new field mapping and graphics software will consolidate field graphics functionality into an efficient process and provide a current, supported solution.

Q. Please explain the Electric Infrastructure Attachments project.

A. The Electric Infrastructure Attachments ("IA") project will research, create a request for proposal ("RFP"), evaluate solution alternatives, design, develop and implement software to replace the existing functionality of the IA System Design and Standards ("SDS") Microsoft Access database. Unlike the current solution, the new solution will be IT supported.

Q. What benefits will this project provide?

A. Purchasing and implementing an IT-supported software platform that provides current functionality of the SDS Database, as well as new functionality will benefit both the Company and its customers by: (i) integrating data across several platforms including SAP, GIS, the National Joint Utility Notification System, and location-specific field design related materials as documentation of the assets inspected; (ii) providing a more efficient approach to fulfill information requests; (iii) affording a history of pole attachments at a specific location; and (iv) reducing waste through improved processes.

Q. What is the scope and cost of this project?

A. The scope of this project includes: (i) researching industry solutions, (ii) creating an RFP; (iii) evaluating options and selecting a solution; and iv) designing and implementing a solution. As stated by Company witness Tolonen, this project includes $727,000 in capital costs and $80,500 in O&M costs.

Q. What alternatives did the Company consider?

A. Alternatives considered include: (i) select and implement a fully integrated, IT-supported solution that replaces the existing functionality of the IA SDS database; (ii) develop an in-house replacement for the SDS database through updates to the existing database or SharePoint; and (iii) continue to use the current SDS database. Alternative two was not chosen because this option would not integrate with Corporate systems, exacerbating ongoing issues with data discrepancies and client dissatisfaction making it an inferior solution. Alternative three is unacceptable due to the stated business risks. The first alternative was selected because it will provide for an integrated, IT-supported solution.

Q. Please explain the Real-Time Electric System Access in the Field project.

A. This project provides field crews with access to real-time network, asset, and outage information using an interface on mobile and hand-held devices that includes highly configurable map displays, substation one-lines, and real-time tabular displays. This project will implement and integrate these capabilities in the field, as well as provide for the organizational change management necessary for project success.

Q. What benefits will this project provide?

A. This new technology will provide: (i) a comprehensive, end-to-end integrated solution that will provide field personnel with the ability to monitor and update the real-time, as-operated grid status in the field, eliminating the need for continual dialog with System Operations teams; and (ii) efficient and effective assignment of work to field technicians improving safety, communication, documentation, and productivity.

Q. What is the scope and cost of this project?

A. The scope of this project includes: (i) assessing the capabilities and value of each module of the OSI Compass solution to determine functionality to be included in scope; (ii) evaluating work processes of field worker roles to determine those roles to be included in scope; (iii) evaluating options and selecting a solution; (iv) developing and executing organizational change management activities; and (v) designing and implementing the technology solution. As stated by Company witness Tolonen, this project includes $252,000 in O&M costs.

Q. What alternatives did the Company consider?

A. Alternatives considered include: (i) continue to follow existing field processes that require back-and-forth radio communication to validate, update, and change system status; and

(ii) implement a solution to enable as-operated, real time electric system grid status changes from the field. The first alternative was not selected because although three-way communication procedures have been established, they are prone to human error and pose a safety risk. The second alternative was selected for the aforementioned benefits.

Q. Please explain the Electric Distribution Asset Management project.

A. This project will develop a Distribution Asset Management strategy, as discussed in the Grid Modernization Strategy section of my direct testimony, with corresponding process and technology implementation plans and objectives.

Q. What benefits will this project provide?

A. The Company will gain value from this project through: (i) creating a standardized process for designers and field resources to collect and manage asset data, reducing waste and rework associated with current processes; (ii) optimizing planning and management of distribution assets, resulting in investments of highest value; (iii) establishing a channel for the Company to develop and manage asset health conditions on the distribution system, optimizing the operation and maintenance investments of distribution assets; and (iv) improving the quality of Company electric distribution asset data, optimizing asset performance and providing opportunities to leverage quality data to support other engineering and operations efforts.

Q. What is the scope and cost of this project?

A. The project scope includes: (i) developing a Distribution Asset Management strategy with a corresponding process and technology implementation plans and objectives; (ii) designing and implementing optimized processes and supporting technology solutions; (iii) implementing an Asset Integrity Management Program leveraging industry standards;

(iv) evaluating, designing, and implementing tools to optimize investment planning and asset health management; (v) implementing a distribution asset system of record repository; and (vi) designing and implementing the organizational change management necessary to ensure success. As stated by Company witness Tolonen, this project includes $1,984,000 in capital costs and $751,000 in O&M costs.

Q. What alternatives did the Company consider?

A. The Company considered continuing to fund and implement electric distribution asset-based technology solutions as separate projects including: (i) upgrading the GIS with the next major data model version and integrating affected applications; (ii) integrating GIS with the work management system (SAP); (iii) enhancing mobile data; and (iv) designing asset data processes. This alternative was not selected as it does not consider technology, process, people, and data interdependencies. The Company selected the approach outlined here because it creates the opportunity to identify, prioritize, and address key gaps in current asset data collection processes, addresses the technology and process inter-dependencies, and provides for distribution asset management planning and investment optimization.

Q. Please explain the Replacement of Testing Software for the Electric MTC project.

A. This project will replace the existing software for MTC test boards and will implement four multi-position test boards, increasing the output of tested meters and ensuring future software stability.

Q. What benefits will this project provide?

A. The project will add value by: (i) increasing meter testing output, enabling Company employees to work more efficiently; (ii) implementing a multi-position test board that integrates meter qualification, meter demand, and meter accuracy; and (iii) avoiding increasing Microsoft support costs. An additional benefit specific to the new software is the creation of a centralized database where all the boards access one database, AMI device support, power quality capture, and web reports.

Q. What is the scope and cost of this project?

A. The project scope includes: (i) replacing the existing software with a version compatible with the Company's current Windows operation system version; (ii) writing new interfaces for test boards to SAP; and (iii) replacing four existing test boards with multi-position test boards. As stated by Company witness Tolonen, this project includes $24,280 in O&M costs.

Q. What alternatives did the Company consider?

A. Alternatives considered include: (i) purchase new software, rebuild interfaces, and replace four single-position test boards with two three-position test boards; (ii) purchase new software and rebuild interfaces, but do not replace the four single position test boards; and (iii) do not complete the upgrade. The second and third options were not chosen because they do not allow the Company to reap the benefits of the new three-position test boards. The first option was chosen because it allows the Company to keep old test boards for additional capacity and creates more efficiencies, which result in a higher output of tested meters.

VIII. O&M SPENDING PROGRAMS

A. O&M Spending Programs

Q. What is included in the Company's distribution O&M spending?

A. The Company's distribution O&M spending includes: (i) funding for the Company's ongoing distribution Operations and Engineering functions, and (ii) funding for certain internal organizations that support both functions.

Q. Please describe how the Operations and Engineering functions are structured.

A. Operations includes nine O&M programs, further subdivided into 31 sub-programs. Similarly, Engineering includes five O&M programs, comprised of 25 sub-programs.

IX. ELECTRIC DISTRIBUTION O&M EXPENSES

Q. Please describe your Distribution O&M Exhibits.

A. I am sponsoring five O&M exhibits with my direct testimony. Specifically:

- Exhibit A-36 (RTB-9), page 1, provides a summary of the actual and projected electric and common O&M expenses for the years 2018 (actual), 2019 (projected), 2020 (projected bridge), and 2021 (projected test year);
- Exhibit A-36 (RTB-9), page 2, provides a summary of the actual and projected electric and common O&M expenses for the years 2018 (actual), 2019 (projected), 2020 (projected bridge), and 2021 (projected test year) split between labor and non-labor;
- Exhibit A-37 (RTB-10) provides a summary of the actual and projected electric and common O&M expenses for the years 2018 (actual), 2019 (projected), 2020 (projected bridge), and 2021 (projected test year) split between Electric Operations and Electric Engineering and Support;
- Exhibit A-38 (RTB-11) (2 pages) provides a summary of the actual and projected electric and common O&M expenses for the years 2018 (actual), 2019 (projected), 2020 (projected bridge), and 2021 (projected test year) identified by program and sub-program; and
- Exhibit A-39 (RTB-12) provides the actual and projected electric and common O&M expenses for the years 2014 through 2018 (columns (b) through (f)), five-year average of years 2014 through 2018 (column (g)), 2019 projected (column (h)), 2020 projected bridge year (column (i)), the 2021 projected test

year (column (j)), and the 2021 projected test year less the five-year average of years 2014 through 2018 (column (k)) identified by program and sub-program as appropriate.

Q. Please explain the source for the actual O&M expenses utilized in your exhibits.

A. For the years 2014 through 2018, actual O&M expenses for were taken from Consumers Energy's internal reporting records. For 2019, O&M expenses are a mix of actual expenses for the first nine months of the year, with projections for the final three months. All other years were projected as detailed below.

Q. Do 2018 actual and 2019 projected O&M expenses represent continuing functions and activities?

A. Yes. The Company projects that the functions and activities represented by the expenses for the 2021 test year will be similar and consistent with the functions and activities that were performed in 2018 and 2019, plus some new maintenance initiatives.

Q. What new maintenance initiatives is the Company planning?

A. The Company is proposing to increase its substation maintenance O&M to enable a more robust inspection and repair regime. The Company developed a concept approval in support of this initiative, as listed in Exhibit A-41 (RTB-14), line 34. This initiative will impact O&M spending in the Substations Reliability – LVD, Substations Reliability – HVD, Substations Demand – LVD, Substations Demand – HVD, and Planning – HVD System O&M sub-programs.

The Company is also proposing to increase its helicopter patrols of the HVD system from one per year to two per year, to better identify failures on the HVD system. This will impact spending in the Planning – HVD System O&M sub-program.

Q. Has the Company included any Transmission O&M expenses in the test year in this filing?

A. No, it has not. Those expenses are developed through the MISO Tariff and processed through the Company's PSCR proceedings.

X. ELECTRIC OPERATIONS

Q. Please detail the O&M programs which comprise Electric Operations.

A. Electric Operations is broken down into the following nine programs:

- O&M Associated with Construction;
- Non-Forestry Reliability (note: Forestry-related Reliability is discussed in Company witness Shellberg's testimony);
- Operations, Maintenance, and Metering;
- Service Restoration;
- Field Operations;
- Compliance and Controls;
- Planning and Scheduling;
- Operations Performance; and
- Operations Management.

A. O&M Associated with Construction

Q. Please describe expenses associated with the O&M Associated with Construction sub-program as shown on Exhibit A-38 (RTB-11), page 1, line 3.

A. To supply electricity at proper voltage levels, the Company must purchase transformers, regulators, auto boosters, and isolators for use across the electric distribution system. Costs in this program account for the O&M spending associated with these necessary equipment purchases and related capital investments. An initial equipment purchase of the above listed items is allocated first to the material, labor, and loadings costs of the Company's capital programs. At purchase, credits are accounted for and are subsequently allocated back to this O&M program when the equipment is installed or retired. Credits and costs are reconciled on a monthly basis. Note that, for transformers, the time lag and rate changes between the purchase and installation may cause a small non-zero balance. Expenses for O&M Associated with Construction are projected to be a net of $0.00 in the 2020 bridge year and net $0.00 in the 2021 test year.

Q. How did the Company determine the $0.00 (zero dollars) net expense for this program?

A. The Company's forecast is based on the projected needs in the various capital programs for transformers, regulators, auto boosters, and isolators. Exhibit A-38 (RTB-11), page 1, line 1, designates the Company's $9,000,000 projected spending level in this program in 2020 and $7,716,000 projected spending level in 2021. These expenses account for the purchase of transformers, regulators, auto boosters, and isolators. Exhibit A-38 (RTB-11), line 2, shows that the Company expects to offset that with $9,000,000 in transformer credits in 2020 and $7,716,000 in transformer credits in 2021, resulting in a net $0 in expense.

Q. Please explain what constitutes a transformer credit.

A. Transformers are purchased through capital programs, as discussed earlier in my direct testimony. In addition to the direct cost for the transformers, there is a first-set credit value, which offsets the cost of labor for installation. When transformers are purchased and received, the first-set credit value for each transformer is totaled at the end of each month and credited back to the cost of construction to give this O&M program credit for the installation labor. The credits are intended to entirely offset the labor costs, but due to the lag discussed above, there may at times be residual net expense.

B. <u>Non-Forestry Reliability</u>

Q. Please describe the O&M expenses related to the Non-Forestry Reliability Program, as shown in Exhibit 38 (RTB-11), page 1, line 8.

A. The Company's Non-Forestry Reliability O&M Program objectives are (i) minimizing the occurrence of outages; (ii) avoiding outages through effective response; (iii) shortening outage durations; and (iv) improving system assets. The Company accomplishes these objectives by inspecting and monitoring system equipment. The Company also conducts a proactively managed forestry line clearing program, as discussed in Company witness Shellberg's testimony. Forestry expenses are not included in the Non-Forestry Reliability O&M Program.

The Company is projecting Non-Forestry Reliability O&M expenses of $3,458,000 in 2020 and $7,125,000 in the 2021 projected test year, as detailed in Exhibit A-38 (RTB-11), page 1, line 8, columns (d) and (e), respectively. The Non-Forestry Reliability O&M expense in 2018 was $3,745,000, and is projected to be $3,211,000 in 2019, as shown in Exhibit A-38 (RTB-11), page 1, line 8, columns (b) and (c), respectively. The most significant changes in O&M expense in Non-Forestry Reliability for the 2021 test year result from increases to three of the four sub programs included within the program.

Q. What are the sub-programs contained within the electric Non-Forestry Reliability O&M Expense Program?

A. The four sub-programs, as shown in Exhibit A-38 (RTB-11), page 1, lines 4 through 7, are: (i) Lines Reliability—LVD; (ii) Lines Reliability—HVD; (iii) Substations Reliability – LVD; and (iv) Substations Reliability – HVD.

Q. In which sub-programs do the significant increases in O&M expenses fall?

A. There is a significant increased expense in Lines Reliability—LVD, Substations Reliability—LVD, and Substations Reliability—HVD. Increases are discussed in detail below.

1. <u>Lines Reliability</u>

Q. Please describe what programs or spending items are contained in the Lines Reliability program—LVD.

A. The Company's Lines Reliability—LVD O&M sub-program supplements the LVD Lines Reliability Capital Program by funding activities that promote the long-term safe and reliable operation of the LVD system, including maintenance and costs associated with new grid devices and connected equipment. New equipment includes new devices on the LVD system such as line sensors, regulator controllers, capacitor bank controllers, and automatic transfer reclosers. Additionally, O&M will cover firmware upgrades, communication costs, and troubleshooting in case of failed equipment.

Q. Please describe the test year O&M expenses related to the Lines Reliability—LVD sub-program, as shown in Exhibit A-38 (RTB-11), page 1, line 4.

A. The Company is projecting Lines Reliability—LVD O&M expenses of $280,000 in 2020 and $1,452,000 in the projected test year ending December 31, 2021, as set forth in Exhibit A-38 (RTB-11), line 4, columns (d) and (e), respectively.

Q. What has been the historical spending in this program?

A. The Lines Reliability—LVD O&M actual expense in 2018 was $56,000, and $72,000 in 2019, as detailed in Exhibit A-38 (RTB-11), page 1, line 4, columns (b) and (c), respectively. Exhibit A-39 (RTB-12), line 4, details the historical (2014-2018) spending in this sub-program, as well as projected spending for 2019-2021.

Q. Explain the increase from the historical and actual amounts to the 2021 test year.

A. The increase in spending between historical and test year amounts are largely for the equipment described above to support new Grid Modernization capital investments.

Q. What was the basis for determining the $1,452,000 of O&M expenses in test year 2021 as requested for this program?

A. Spending in this program is primarily driven by demand. Expenses include incremental repairs to the LVD lines infrastructure that are not captured by the Company's capital programs, making an increase in O&M spending necessary.

Q. Please describe the activities represented by the $1,452,000 of O&M expenditures in test year 2021 requested for this program.

A. The exterior of pad mounted equipment is visually inspected each year for any signs of leaking oil, holes that expose electrical components, or missing labels. If found, the holes are patched, and labels are replaced. If equipment is irreparable, replacement of equipment is done under the LVD Lines Demand Failures Program. This program also covers LVD Security Assessments. As described in the LVD Lines Demand Failures Capital Program, all LVD feeders are inspected on a six-year cycle for public and employee safety, and for reliability concerns. Issues identified that are not capital components are addressed in this O&M Program. Some examples 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;
- Bringing assets up to current 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;
- Adding or correcting existing labels for devices in the field to match our records; and
- Adding animal mitigation due to past animal related outages.

Q. Please describe the benefit of O&M expenses related to the Lines Reliability—LVD Program.

A. The Lines Reliability—LVD O&M Program supplements the LVD Lines Reliability Capital Program and funds activities that ensure the long-term safe and reliable operation of the LVD system. The program strives to improve public and employee safety, addresses imminent events, reduces customer outage frequency (SAIFI), and reduces the number of emerging repetitive outage customers (CEMI), as well as customer outage durations (CAIDI and SAIDI).

The primary benefit of reducing outages is increased reliability. However, the Company also utilizes these O&M dollars to identify and address safety concerns to protect the public and employees. For example, poorly sagged conductors could inadvertently contact one another in windy conditions causing outages. Installing bird diverters on the lines in an area known for bird issues can both prevent outages and prevent animal death.

Q. Please describe what programs or spending items are contained in the Lines Reliability Program—HVD.

A. The Company's Lines Reliability—HVD O&M sub-program includes the expense portion of the Company's HVD pole inspections, which occur on a 12-year cycle, and MOABS tests, which occur once per year.

Q. Please describe the O&M expenses related to the Lines Reliability—HVD sub-program, as shown in Exhibit A-38 (RTB-11), page 1, line 5.

A. The Company is projecting Lines Reliability—HVD O&M expenses of $125,000 in 2020 and $125,000 in the projected test year ending December 31, 2021, as shown in Exhibit A-38 (RTB-11), page 1, line 5, columns (d) and (e), respectively.

Q. Please explain the value of the work and related expenses requested for the Lines Reliability –HVD Program.

A. Pole inspections and MOABS testing are fundamental in maintaining HVD line assets. A 12-year pole inspection cycle in the state of Michigan is supported by established wood pole decay severity zones. The inspection data and information gathered through this O&M sub-program is key information used to assist in identifying line capital projects.

Q. Please explain the basis for determining the projected 2021 test year O&M expense amount of $125,000 for the Lines Reliability—HVD O&M Program.

A. The work activity and expenses for the Lines Reliability—HVD O&M sub-program in 2021 are relatively similar to those included in the 2019 budgeted expense amount of $132,000 and are significantly less than spending in this sub-program between 2014 and

2018, as displayed in Exhibit A-39 (RTB-12), line 5, column (g). The decrease between the projected test year and the five-year average amount can be attributed to the capitalization of lines pole top equipment, such as crossarms and insulators, which began in 2015.

2. Substation Reliability

Q. Please describe the work related to the O&M expenses for the Substation Reliability—LVD sub-program as shown in Exhibit A-38 (RTB-11), page 1, line 6 .

A. The goal of the Company's Substation Reliability—LVD O&M sub-program is to maintain the safety and reliability of LVD distribution substations, through substation and substation equipment inspections, recloser and circuit breaker test operating, and substation battery maintenance. This sub-program includes required environmental inspections under the Spill Prevention, Control and Countermeasure ("SPCC") Program. Funding for 80% of the total HVD and LVD substation mowing and weed spraying expenses is included in this sub-program and consists of one weed spray per year and a five-month (May-September) mowing program with a two-times-a-month mow interval. Issues identified by inspections or patrols under this program are corrected through work orders in the Substation Demand—LVD O&M Program, the LVD Substation Reliability capital program, or the LVD Substation Demand Failures capital program.

Q. Please describe the O&M expenses related to the Substation Reliability—LVD sub-program, as shown in Exhibit A-38 (RTB-11), page 1, line 6.

A. The Company is projecting Substation Reliability—LVD O&M expenses of $1,700,000 in bridge year 2020 and $2,820,000 in the projected test year ending December 31, 2021, as set forth in Exhibit A-38 (RTB-11), page 1, line 6, columns (d) and (e), respectively.

Q. What has been the historical spending in this program?

A. The Substations Reliability—LVD O&M actual expense in 2018 was $2,090,000, and $1,800,000 in 2019, as detailed in Exhibit A-38 (RTB-11), page 1, line 6, columns (b) and (c), respectively. Exhibit A-39 (RTB-12), line 6, details the historical (2014-2018) spending in this sub-program, as well as projected spending for 2019-2021.

Q. Explain the increase from the historical and actual amounts to the 2021 test year.

A. The increase in spending in this sub-program is driven primarily by the Company's initiative to increase inspections and repair of its substations, as described above and further explained in Exhibit A-41 (RTB-14).

Q. Please describe the work related to the O&M expenses for the Substation Reliability—HVD sub-program as shown in Exhibit A-38 (RTB-11), page 1, line 7.

A. The goal of the Company's HVD Substation Reliability O&M 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 Substation Reliability—HVD sub-programs, as shown in Exhibit A-38 (RTB-11), page 1, line 7.

A. The Company is projecting Substations Reliability—HVD O&M expenses of $1,353,000 in bridge year 2020 and $2,728,000 in the projected test year ending December 31, 2021, as set forth in Exhibit A-38 (RTB-11), page 1, line 7, columns (d) and (e), respectively.

Q. What has been the historical spending in this program?

A. The Substations Reliability—HVD O&M actual expense in 2018 was $1,422,000, and $1,207,000 in 2019, as detailed in Exhibit A-38 (RTB-11), page 1, line 7, columns (b) and (c), respectively. Exhibit A-39 (RTB-12), line 7, details the historical (2014-2018) spending in this sub-program, as well as projected spending for 2019 through 2021.

Q. Explain the increase from the historical and actual amounts to the 2021 test year.

A. The increase in spending in Substations Reliability – HVD is also driven primarily by the Company's initiative to increase inspections and repair of its substations, as described above and further explained in Exhibit A-41 (RTB-14).

Q. Please describe the benefits to customers provided by the Substations Reliability—LVD and Substations Reliability—HVD sub-programs.

A. In 2019, the average LVD substation outage resulted in 0.123 SAIDI minutes; whereas, in the same year, the average HVD substation outage resulted in 0.068 SAIDI minutes. Consequently, each outage avoided has a significant benefit to system reliability. Additionally, there are public and Company safety benefits from having periodic inspections of substations. Lastly, maintaining equipment allows the system to be operated as intended and at its most efficient level.

B. <u>Operations, Maintenance, and Metering</u>

Q. Please describe the work related to the Operations, Maintenance, and Metering Program (w/out Service Restoration), as shown in Exhibit A-38 (RTB-11), page 1, line 21.

A. The Company's HVD Operations, Maintenance, and Metering O&M expenses consist of three demand sub-programs and the expenses associated with the Electric Equipment Repair Center located in Alma. Additionally, the expense for DGA testing of LVD and substation equipment are included in this sub-program. The Company's LVD Operations, Meter Services, Meter Readings O&M spending includes a number of demand programs related to the front-line operations of the distribution grid.

Q. What are the sub-programs contained within the Electric Operations, Maintenance, and Metering O&M expense program?

A. The 12 sub-programs, as shown in Exhibit A-38 (RTB-11), page 1, lines 9 through 20, are: (i) Lines Demand—HVD; (ii) Substations Demand—LVD; (iii) Substations Demand—HVD; (iv) Corrective Maintenance; (v) Staking; (vi) Meter Services and Meter Credits; (vii) Streetlighting; (viii) Service Calls; (ix) Alma Equipment Repair; (x) Meter Reading; (xi) Meter Tech & Management System Support; and (xii) Smart Energy MTC—Electric.

Q. Please describe the O&M expenses related to the Operations, Meter Services, Meter Readings Program, as shown in Exhibit A-38 (RTB-11), page 1, line 21.

A. The Company is projecting Operations, Maintenance, and Metering O&M expenses of $33,027,000 in the 2020 bridge year and $38,937,000 in the 2021 projected test year, as set forth in Exhibit A-39 (RTB-12), line 21, columns (d) and (e), respectively. There is no significant increase in any of the 12 sub-programs listed above over the historical actual spending in any sub-program for the years 2014 through 2018, except for (i) the Smart Energy MTC—Electric sub-program, which only had two years of historical spend to calculate, and (ii) the Meter Reading sub-program, which has projected test year O&M spending that is $6,395,000 less than historical average spending for that sub-program. Sub-program averages are detailed in Exhibit A-39 (RTB-12), lines 9 through 20, column (g).

1. Lines Demand

Q. Please describe the work related to the Lines Demand sub-programs as shown in Exhibit A-39 (RTB-11), page 1, line 9.

A. The Company's Lines Demand O&M sub-programs include certain expenses for repairs to 46 kV and 138 kV lines equipment. This sub-program also includes associated on-call costs for line 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. Please explain the basis for determining the projected test year O&M expense amount of $940,000 for the Lines Demand O&M sub-program.

A. The Company is projecting Lines Demand O&M expenses of $735,000 in the 2020 bridge year and $940,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 9, columns (d) and (e), respectively. Bridge and test year expenses for the Lines Reliability O&M sub-program are increasing slightly in comparison to those projected to be realized in 2019 ($325,000) but remain generally less than the typical historical spending during years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 9.

2. <u>Substation Demand—LVD and HVD</u>

Q. Please describe the general work associated with both the Substation Demand—LVD and HVD sub-programs.

A. These sub-programs respond to failures resulting in customer outages or equipment outages, poor testing results (e.g., infrared inspections, oil sampling, etc.), and substation asset management database algorithms, supporting the Company's safety and reliability objectives by ensuring customer and electric system safety, outage restoration, and repairs to equipment to maintain operational functionality of the electric system.

Q. Please describe the work related to the Substations Demand—LVD sub-program, as shown in Exhibit A-38 (RTB-11), page 1, line 10.

A. The Company's Substations Demand—LVD 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.

Q. Please describe the O&M expenses related to the Substations Demand—LVD sub-program.

A. The Company is projecting Substations Demand—LVD O&M expenses of $2,953,000 in the 2020 bridge year and $3,975,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 10, columns (d) and (e), respectively. Test year work activity and expenses for the Substations Demand—LVD O&M sub-program are increasing in comparison to those projected to be realized in 2019 ($2,939,000) but remain generally consistent with amounts typically incurred by the Company during years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 10. The increase that does take place is largely due to the Company initiative to increase its substation inspection and repair efforts, as described above and in Exhibit A-41 (RTB-14).

Q. Please describe the work related to the Substations Demand—HVD sub-program, as shown in Exhibit A-38 (RTB-11), page 1, line 11.

A. The Company's Substations Demand—HVD O&M sub-program includes expenses for unplanned and emergent restoration, as well as corrective maintenance on HVD and Strategic Customer substation equipment and facilities.

Q. Please describe the O&M expenses related to the Substations Demand—HVD sub-program.

A. The Company is projecting Substations Demand—HVD O&M expenses of $2,160,000 in the 2020 bridge year and $3,835,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 11, columns (d) and (e), respectively. Test year work activity and expenses for the Substations Demand—HVD O&M sub-program are increasing in comparison to those projected to be realized in 2019 ($2,280,000) but are relatively consistent with amounts typically incurred by the Company during the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 11. The increase that does take place is largely due to the Company initiative to increase its substation inspection and repair efforts, as described above and in Exhibit A-41 (RTB-14).

3. Corrective Maintenance

Q. Please describe the work related to O&M spending on Corrective Maintenance sub-program, as shown in Exhibit A-38 (RTB-11), page 1, line 12

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. These work orders are categorized for reporting purposes among two main activity types: investigations and maintenance. 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.

Q. Please describe the O&M expenses related to the Substations Demand—HVD sub-program.

A. The Company is projecting Corrective Maintenance O&M expenses of $4,549,000 in the 2020 bridge year and $5,549,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 12, columns (d) and (e), respectively. Test year expenses for the Corrective Maintenance O&M sub-program are increasing slightly in comparison to those projected to be realized in 2019 ($4,897,000) but generally remain less than the amounts typically incurred by the Company during the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 12.

4. <u>Staking</u>

Q. Please describe the work associated with O&M spending on the Company's Staking sub-program, as shown in Exhibit A-38 (RTB-11), page 1, line 13

A. The Staking sub-program supplies external resources to locate and mark underground electric distribution facilities in accordance with the MISS DIG law (Public Act 174 of 2013), a key component of securing public and employee safety. There are approximately 400,000 orders in a typical year. Work order numbers and projected expenses are based on historical numbers.

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

A. The Company is projecting Staking O&M expenses of $2,929,000 in the 2020 bridge year and $3,017,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 13, columns (d) and (e), respectively. The expenses for the Staking O&M sub-program are increasing slightly in comparison to those projected to be realized in 2019 ($2,876,000) but generally remain less than the amounts typically incurred by the Company during the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 12.

5. <u>Meter Services and Credits</u>

Q. Please describe the work related to the Company's O&M spending in the Meter Services (and Credits) sub-program as shown on Exhibit A-38 (RTB-11), page 1, line 14.

A. This O&M sub-program funds Electric Meter Operations ("EMO"), whose expenses are offset by first set and retirement credits of both meters and metering transformers. EMO responds to customer-initiated and Company-generated orders for replacement or repair of existing meters. EMO also conducts handheld read routes, which are meter reads outside of the Company's regular Meter Reading Program that require special equipment.

Q. Please explain the Credit portion of this O&M program.

A. Similar to transformer credits, meters are purchased through capital programs discussed earlier in my direct testimony. In addition to the direct cost for meters, a first-set credit value is included to offset the cost of labor for installation. When meters are purchased and received, the first-set credit value for each meter is totaled at the end of each month and credited back to O&M for the installation labor. The credits are intended to entirely offset the labor costs, but due to the monthly lag discussed above, there is some net expense.

Q. Please describe the O&M expenses related to the Meter Services (and Credits) sub-program.

A. The Company is projecting Meter Services O&M expenses of $2,418,000 in the 2020 bridge year and $2,832,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 14, columns (d) and (e), respectively.

The expenses for the Meter Services O&M sub-program are increasing in comparison to those projected to be realized in 2019 ($57,000) but remain significantly less than the amounts typically incurred by the Company during the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 14.

6. Streetlighting

Q. Please describe the O&M work and expenses related to the Streetlighting sub-program. Streetlighting O&M as shown in Exhibit A-38 (RTB-11), page 1, line 15.

A. Streetlighting O&M supports the personnel and materials necessary to complete streetlight replacement maintenance activities.

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

A. The Company is projecting Streetlighting O&M expenses of $1,168,000 in the 2020 bridge year and $1,156,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 15, columns (d) and (e), respectively. The expenses for the Streetlighting O&M sub-program are consistent with those projected to be realized in 2019 ($1,488,000) and are well below the amounts typically incurred by the Company during the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 15. Expenses in this sub-program have trended downward as the Company has been able to capitalize more streetlight repairs.

7. <u>Service Calls</u>

Q. Please describe the work associated with the O&M expenses for the Service Calls sub-program as shown in Exhibit A-38 (RTB-11), page 1, line 16.

A. The Company estimates, based on historical numbers, that employees will respond to between 19,500 and 20,000 discrete service calls during the year.

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

A. The Company is projecting Service Call O&M expenses of $3,589,000 in the 2020 bridge year and $4,589,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 16, columns (d) and (e), respectively.

The expenses for the Service Call O&M sub-program are higher that the five-year average amount of $2,824,000 for the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 16, column (g), but are consistent with those projected to be realized in 2019 ($4,510,000). Expenses in staffing and contracted services, as well as “make ready” calls contribute to overall increases in this sub-program.

8. <u>Alma Equipment Repair</u>

Q. Please describe the work related to O&M expenses for the Alma Equipment Repair sub-program, as shown in Exhibit A-38 (RTB-11), page 1, line 17.

A. The Company’s Alma Equipment Repair O&M sub-program includes maintenance activities (testing, repairing, reconditioning) for assets such as mobile substation equipment, substation oil processing equipment, and substation power transformer cooling equipment. The sub-program also includes activities such as substation equipment acceptance testing and ensuring compliance with all environmental regulations regarding the handling, storage, and disposal of equipment containing PCBs. These activities are considered base level maintenance for system reliability and emergency response to demand outages.

Q. Please describe the O&M expenses related to the Alma Equipment Repair sub-program.

A. The Company is projecting Alma Equipment Repair O&M expenses of $1,159,000 in the 2020 bridge year and $1,169,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 17, columns (d) and (e), respectively. The expenses for the Alma Equipment Repair O&M sub-program are consistent with those projected to be realized in 2019 ($1,002,000) and generally remain in line with amounts typically incurred by the Company during the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 17.

9. <u>Meter Reading</u>

Q. Please describe the Company's Meter Reading O&M sub-program as detailed in Exhibit A-38 (RTB 11), page 1, line 18.

A. The Meter Reading sub-program is comprised of

- Field employees reading meters and performing annual inspections of padmount transformers;
- Client water meter reads; and
- Gas leak surveys.

In addition, the sub-program funds office support staff to manage scheduling and re-routing efforts to optimize efficiency in field operations.

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

A. The Company is projecting Meter Reading O&M expenses of $1,778,000 in the 2020 bridge year and $1,827,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 18, columns (d) and (e), respectively.

The O&M expenses for the Meter Reading sub-program are consistent with those projected to be realized in 2019 ($1,708,000), but are significantly lower than the amounts typically incurred by the Company during the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 18, as the Company's deployment of smart meters has reduced the need for direct meter reading.

10. <u>Meter Technology and Management System Support</u>

Q. Please explain the Meter Technology and Management System Support sub-program as detailed in Exhibit A-38 (RTB 11), page 1, line 19.

A. This sub-program funds MTC activities to support the LVD Metering New Business capital sub-program. This O&M sub-program funds the testing, refurbishing, and technology evaluation of the Company's capital program-related metering equipment. Activities include testing a sample of each shipment of new meters and metering transformers prior to release for use in the field. The required O&M spending for this sub-program is based on investments in the capital metering sub-program.

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

A. The Company is projecting Meter Technology and Management System Support O&M expenses of $1,273,000 in the 2020 bridge year and $1,320,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 19, columns (d) and (e), respectively. The O&M expenses for the Meter Technology and Management System Support sub-program are consistent with those projected to be realized in 2019 ($1,222,000) and generally remain consistent with the amounts typically incurred by the Company during the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 19.

11. <u>Smart Energy MTC—Electric</u>

Q. Please describe the Company's Smart Energy—MTC sub-program as detailed in Exhibit A-38 (RTB 11), page 1, line 20.

A. The Smart Energy MTC—Electric budget consists of two components: (i) communications backhaul; and (ii) meter software maintenance charges. The charges are fixed by a contract that establishes the charging rates through 2022. These rates are based on the number of active electric smart meters the Company has installed at customer locations, and meter inventory levels required to meet new business and meter failure requirements throughout the year. As these charges are fixed, the spending forecast is based on the projected number of meters and is adjusted annually based on projections for new business, regulatory requirements, or other large projects.

Q. Please describe the O&M expenses related to the Smart Energy MTC—Electric sub-program.

A. The Company is projecting Smart Energy MTC—Electric O&M expenses of $8,316,000 in the 2020 bridge year and $8,729,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 20, columns (d) and (e), respectively. The O&M expenses for the Smart Energy MTC—Electric sub-program are consistent with those projected to be realized in 2019 ($8,694,000).

C. Service Restoration

Q. Please describe the O&M work and expenses related to the Service Restoration sub-program.

A. Company witness Houtz discusses the entirety of this sub-program in her direct testimony. Service Restoration O&M expense is projected to be $83,670,000 in 2019, $38,726,000 in 2020, and $65,100,00 for the 2021 projected test year. O&M dollars in this sub-program support activities described within Company witness Houtz's direct testimony.

D. Field Operations

Q. Please describe the O&M work related to the Field Operations Program as shown in Exhibit A-38 (RTB-11), page 1, line 31.

A. The Field Operations Program consists of the cost of training, supervision, facilities, and facilities maintenance for the Company's in-field operations teams. These costs are planned annually based on the expected costs to maintain an in-field operations team to carry out the various activities required for supporting the safe, reliable, and efficient operations of our electric distribution system. This program includes labor expenses for supervision and leadership for electric LVD and HVD operations. Expenses include the cost of training, supervision, facilities, and facilities maintenance for in-field operations teams.

Q. What are the sub-programs in the Field Operations O&M expense program?

A. The seven sub-programs, as shown in Exhibit A-38 (RTB-11), page 1, lines 24 through 30, are: (i) Training; (ii) Tools; (iii) Field Operations Expenses; (iv) Indirect Labor/Labor Variation; (v) Supervision/Admin Staff; (vi) Smart Energy Operations Center; and (vii) Grid Management—Distribution.

Q. Does the Field Operations Program include additional sub-programs that are different from the Company's last filing?

A. Yes. This filing includes Grid Management expenses in the Fields Operations Program. Grid Management had previously been a separate and discrete line item in Case No. U-20134.

Grid Management is responsible for providing statewide 24/7 monitoring and control of the electric distribution system. This includes providing statewide coordination of major service restoration efforts and implementing grid automation through the use of grid devices and advanced applications to improve system reliability, power quality, and reduce energy waste.

Q. Please detail the projected O&M spending for the entire Field Operations Program.

A. The Company is projecting Field Operations O&M expenses of $24,275,000 in the 2020 bridge year and $30,479,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 31, columns (c) and (d), respectively. Overall O&M spending in this program generally remains consistent with historical spending, although two sub-programs have increased spending: Training and Supervision/Admin Staff.

Q. Please explain the basis for determining the projected 2021 test year O&M expense amount of $30,479,000 for the Field Operations Program.

A. Expenses in this program are planned annually based on the expected costs to maintain an in-field operations leadership team to carry out the supervisory responsibilities required for supporting the safe, reliable, and efficient operations of our electric distribution system. The projected O&M expense amount includes more field leader overtime associated with the increase of construction and operations field work resulting from the increased level of capital spending in the projected test year.

Q. Please detail the sub-programs, within the Field Operations Program, which have with the most significant amount of O&M expenses.

A. The Grid Management – Distribution, Training, and Supervision/Administrative Staff sub-programs represent the most significant amount of O&M expenses within the Field Operations Program. Additional detail regarding these sub-programs is provided below.

Q. Please describe the O&M work related to the Grid Management—Distribution Program as shown in Exhibit A-38 (RTB-11), page 1, line 30.

Most O&M expenses in this program are for the salaries and expenses of employees operating and supporting the monitoring and control of the electric distribution system. There are also O&M expenses associated with specific investments that are made in this program to improve and streamline operations. The Company's projection includes increased spending to address turnover and maintain necessary staffing levels and to handle a larger volume of switching orders and scheduled outage requests associated with the increased construction and field work.

Q. Please describe the O&M work and expenses related to the Grid Management—Distribution sub-program.

A. Grid Management—Distribution O&M expense is projected to be $3,295,000 for 2019, $4,063,000 for 2020 and $4,513,000 for the projected test year. The O&M expenses for the Grid Management—Distribution sub-program are generally consistent with for the trend of historical spending amounts during the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 30.

Q. Please explain increased O&M spending in the Training sub-program.

A. The Electric Training Program includes skills-based training for Electric Operations employees including Electric Lines, Substation O&M, and Electric Meter. The expenses for operating the Apprenticeship Program includes the labor of those attending training, instructors, and committee members. Aside from the Apprenticeship Program, union labor associated with additional training like continuing education is included in this training category. Increased expenses are due to an increase in the number of Apprentices that will require training to replace the anticipated retirements of skilled field workforce.

Q. Please explain the increased spending in O&M in the Supervision/Administrative Staff sub-program.

A. Increased expense in this category is directly related to the increased need for training and consequent increase in personnel.

E. <u>Compliance and Controls</u>

Q. Please describe the work related to the Compliance and Controls O&M expenses as shown on Exhibit A-38 (RTB-11), page 1, line 33.

A. Compliance and Control-related O&M expenses support expenses related to activities and personnel (including auditors) to maintain compliance with all required regulations.

Q. Please describe the O&M work and expenses related to the Compliance and Control sub-program.

A The O&M expenses for the Compliance and Control sub-program are a new line item, beginning in 2019. Compliance and Control O&M expense is projected to be: $444,000 for 2019, $529,000 for 2020, and $540,000 for the projected test year.

F. Planning and Scheduling

Q. Please describe the work related to the Planning and Scheduling Program O&M expenses as shown on Exhibit A-38 (RTB-11), page 1, line 37.

A. The Planning and Scheduling Program includes O&M costs associated with electric resource planning and closeout, scheduling and dispatch, and contract administration. These costs primarily comprise salaries and business expenses, including the office support functions that include closeout, work planning, contract administration, and business operations support.

These work activities include both capital and O&M for Electric Service and Distribution employees, electric underground and overhead contractors, and EMO. The program is primarily responsible for both weekly and long range planning, scheduling, and dispatching for the following activities: service calls, street lighting, line extension, new business requests, relocations (house moves, build overs, etc.), alterations (upgrades, downgrades, generators), demolitions (lost customers), make ready, failures services, corrective maintenance, capacity, repetitive outage, cutout, pole replacement, sectionalizing, investigations, storm restoration, and EMO.

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

A. The Company is projecting Planning and Scheduling O&M expenses of $5,871,000 in the 2020 bridge year and $6,437,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 37, columns (d) and (e), respectively. The O&M expenses for the Planning and Scheduling sub-program are consistent with those projected to be realized in 2019 ($5,591,000) and are also generally consistent with historical spending amounts incurred during the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12).

G. Operations Performance

Q. Please describe the work related to the Operations Performance O&M expenses as shown on Exhibit A-38 (RTB-11), page 1, line 40.

A. Operations Performance includes salaries and expenses for staff charged with reviewing quality, standardization of services, analysis of engineering systems, and cost across Operations and Engineering departments to provide better service and outcomes.

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

A. The Company is projecting Operations Performance O&M expenses of $1,674,000 in the 2020 bridge year, and $1,716,000 in the 2021 projected test year, as set forth in Exhibit A-xx (RTB-11), page 1, line 40, columns (d) and (e), respectively. The O&M expenses for the Operations Performance sub-program are consistent with those projected to be realized in 2019 ($1,601,000) and are generally consistent with the trend of historical spending amounts incurred during the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 40, column (g).

H. Operations Management

Q. Please describe the work related to the Operations Management sub-program as shown on Exhibit A-38 (RTB-11), page 1, line 41.

A. The Operations Management sub-program includes the salaries and expenses for senior management staff, as well as chargebacks from internal departments specifically related to the operations of the electric distribution grid. This program also includes the electric portion of the reserves for incentive programs accruals, injuries and damages, and electric claims.

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

A. The Company is projecting Operations Management O&M expenses of $1,393,000 in the 2020 bridge year, and $1,608,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 1, line 41, columns (d) and (e), respectively. The O&M expenses for the Planning and Scheduling sub-program are consistent with those projected to be realized in 2019 ($1,673,000) and are generally lower than the historical spending amounts incurred during the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 41, column (g).

XI. ELECTRIC ENGINEERING AND SUPPORT

Q. What are the programs contained within the Electric Engineering and Support section found in Exhibit A-38 (RTB-11), page 2?

A. Electric Engineering and Support is broken down into the following five programs:

- Engineering Support;
- Electric Planning;
- Electric Design;
- Electric Grid Analytics; and
- IT Grid Mod.

A. Engineering Support

Q. Please describe the work related to the Engineering Support Program as shown on Exhibit A-38 (RTB-11), page 2, line 4.

A. The Engineering Support expenses include O&M support for teams and organizations that helps Electric Planning to work efficiently and effectively. Expenses under this program include salaries and expenses for rate case administration, regulatory and compliance, and customer energy specialists.

Q. Please describe the O&M expenses related to the Engineering Support Program.

A. The Company is projecting Engineering Support O&M expenses of $675,000 in the 2020 bridge year and $746,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 2, line 4, columns (d) and (e), respectively. The O&M expenses for the Engineering Support sub-program are consistent with those projected to be realized in 2019 ($640,000), and generally consistent with the historical amounts incurred during the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 46, columns (b) through (f).

B. Electric Planning

Q. Please describe the work related to the Electric Planning Program as shown on Exhibit A-38 (RTB-11), page 2, line 9.

A. Expenses in this program cover salaries and expenses for the distribution functions of the Company's Electric Planning organization, which is broken down into LVD system planning, HVD system planning, and system protection planning. This program historically included expenses for geospatial management and data quality, but that spending is no longer included in this program.

Q. Please describe the O&M expenses related to the Electric Planning Program.

A. The Company is projecting Electric Planning O&M expenses of $7,124,000 in the 2020 bridge year and $8,457,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 2, line 9, columns (d) and (e), respectively. The O&M expenses for the Electric Planning program are consistent with those projected to be realized in 2019 ($8,527,000), and generally consistent with the historical amounts incurred during for the years 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 51.

Q. Are there any noteworthy changes in expenses in this program for the 2021 test year?

A. Yes. The Company is planning to conduct a second helicopter patrol of the HVD system beginning in 2021, in addition to the single helicopter patrol that was already included in the Company's expenses. This additional patrol will be funded in this program, with $362,000 of additional spending funded through the Planning – HVD System line item. A small percentage of the additional patrol will be funded through the Company's FERC-jurisdictional transmission rates.

Q. What is the Company's justification for conducting two helicopter patrols?

A. The second patrol is a key component of the Company's plan to reduce SAIDI through investments in HVD line rebuilds and rehabilitation. Helicopter patrols are crucial in identifying actual and imminent failures on the HVD system, and a second patrol will allow the Company to more thoroughly inspect the HVD system to ensure that all anomalies are properly identified.

C. Electric Design

Q. Please describe the work related to the Electric Design program as shown on Exhibit A-38 (RTB-11), page 2, line 17.

A. The Electric Design program includes salaries and expenses for the distribution functions of the Company's Electric Design organization, including design, standards and document control, joint pole rental, and new initiatives in grid technologies and CVR.

Q. Please describe the O&M expenses related to the Electric Design Program.

A. The Company is projecting Electric Design O&M expenses of $5,505,000 in the 2020 bridge year and $6,283,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 2, line 17, columns (d) and (e), respectively. The O&M expenses for the Electric Design Program are a modest increase from those projected to be realized in 2019 ($4,952,000) and higher than the historical amounts incurred during 2014 through 2018, as displayed in Exhibit A-39 (RTB-12), line 59. As the Company deploys its Grid Modernization strategy, including the implementation of DERs and CVR, new O&M line items have been added to support this work, as shown in Exhibit A-39 (RTB-12), lines 53, 57, and 58. The LVD Design line item is also new in this program, representing a new group created within the Company during internal reorganization.

Q. Please describe the Joint Pole Rental sub-program on Exhibit A-38 (RTB-11), page 2, line 14.

A. The Joint Pole Rental sub-program includes expenses associated with jointly utilizing poles with other utilities (e.g., telecommunications). Expenses include attaching electric facilities to phone company poles. Sharing poles, where possible, saves the Company money by reducing the need to solely install and maintain all Company-owned poles.

Expenses are determined by contractual formulas defined by Joint Use Agreements cellular providers. Expenses and costs are based on the Federal Communications Commission maximum rate calculations for Incumbent Local Exchange Carrier and a contractual multiplier.

D. Electric Grid Analytics

Q. Please describe the work related to the Electric Grid Analytics Program as shown on Exhibit A-38 (RTB-11), page 2, line 19.

A. Electric Grid Analytics expenses include O&M to support salary for an information and technology analytics team, which support work primarily in the grid analytics and grid technologies investment categories described in the section of my direct testimony on the Grid Modernization capital sub-program.

Q. Please describe the O&M expenses related to the Electric Grid Analytics program.

A. The Company is projecting Electric Grid Analytics O&M expenses of $881,000 in the 2020 bridge year and $1,379,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 2, line 19, columns (d) and (e), respectively. The O&M expenses for the Electric Grid Analytics sub-program are slightly higher than those projected to be realized in 2019 ($1,235,000), and are higher than the historical amounts incurred during the years 2017 and 2018, as displayed in Exhibit A-39 (RTB-12), line 61, mostly due to growth in size and responsibilities of this group and related systems.

E. IT Grid Mod

Q. Please describe the work related to the IT Grid Mod Program as shown on Exhibit A-38 (RTB-11), page 2, line 20.

A. The IT Grid Mod Program is a new program in the 2020 bridge year that includes spending on IT needs that support deployment of the Company's Grid Modernization strategy.

Q. Please describe the O&M expenses related to the IT Grid Mod sub-program.

A. The Company is projecting IT Grid Mod O&M expenses of $1,220,000 in the 2020 bridge year and $1,938,000 in the 2021 projected test year, as set forth in Exhibit A-38 (RTB-11), page 2, line 20, columns (d) and (e), respectively.

XII. EXPLANATION OF LOSS STUDY

Q. Please explain what the Loss Study entails and how it is conducted.

A. The purpose of this Study is to allocate system energy and demand losses among the various components of the system by calculating a percentage Loss Factor for each component. This information is used to update loss calculations in electric rates. Loss Factors for the 345 kV, 138 kV, and 46 kV systems and the low side of transformers connected to the 138 kV and 46 kV systems are calculated using hourly system data. The Loss Factor for the Distribution Primary system is also calculated using average data from 400 representative Distribution Primary circuits. Finally, the Loss Factor for the Distribution Secondary system (including secondary transformers) is calculated from the amount of system loss remaining after all other component losses are allocated. The 2018 Loss Study Report is shown in Exhibit A-45 (RTB-18).

Q. How do other Company witnesses in this filing use this Loss Study Report?

A. Company witness Josnelly C. Aponte uses this Loss Study Report in developing the electric cost-of-service study. Additionally, Company witness Michael P. Kelly uses this Loss Study Report to support demand losses and energy losses used in the Company's proposed contract with Hemlock Semiconductor Operations LLC ("HSC"). Company witness Kelly explains the details of this contract, including how HSC's demand losses and energy losses are applied to the contract. HSC is subject to demand losses and energy losses based on both general system losses on the 345 kV and 138 kV transmission system, plus demand losses and energy losses specific to HSC as a customer. As shown in Exhibit A-45 (RTB-18), page 10, the energy loss relative to the 345 kV and 138 kV system is 2.10%. HSC has a customer-specific energy loss of 0.27%, giving HSC a total energy loss of 2.36%. As shown in Exhibit A-45 (RTB-18), page 10, the demand loss relative to the 34 kV and 138 kV system is 2.51%. HSC has a customer-specific demand loss of 0.28%, giving HSC a total demand loss of 2.78%.

Q. Does this complete your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

HEATHER A. BREINING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Heather A. Breining, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Engineering Technical Analyst III. I assumed this position as of June 1, 2013.

Q. Please describe your educational background and experience.

A. In 2001 I earned a Bachelor's degree in Mathematics with a minor in Physics from Spring Arbor University. I have been employed by Consumers Energy for 15 years in various areas including Environmental Services, Transaction Strategies, and Resource Planning.

Q. What are your responsibilities as a Senior Engineering Technical Analyst III?

A. I am responsible for evaluating and analyzing potential compliance options with environmental regulations and/or legislation and assuring that Consumers Energy's capital expenditures for environmental compliance are technically sound, economic, and complement the broader corporate strategy related to delivering safe, reliable, and reasonably priced energy. In addition, I am responsible for managing the Company's emission allowance portfolio as well as providing the necessary environmental documentation to support both Power Supply Cost Recovery and Electric Rate Case proceedings.

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

A. Yes. I testified in the following electric rate cases: Case Nos. U-17990, U-18322, and U-20134. I also testified in the Integrated Resource Plan ("IRP"), Case No. U-20165.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe the environmental regulations with which the Company's electric generating fleet must comply, the cost of compliance with those regulations, as well as the timing and the justification for the investments made to ensure regulatory compliance. My testimony will explain the rationale and description of expenditures related to the Resource Conservation Recovery Act ("RCRA"), Steam Electric Effluent Guidelines ("SEEG") compliance, studies necessary to ensure compliance with Clean Water Act ("CWA") Section 316(b), and the reason for the lack of expenditures in 2019 for certain categories. My direct testimony and exhibits also support Company witness Scott A. Hugo's Exhibit A-12 (SAH-3), Schedule B-5.2.

Q. Are you sponsoring exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-46 (HAB-1)	Projected Capital Expenditures Environmental - Air Quality Compliance Summary of Actual and Projected Electric Capital Expenditures;
Exhibit A-47 (HAB-2)	Projected Capital Expenditures Environmental - Coal Combustion Residuals Compliance Summary of Actual and Projected Electric Capital Expenditures;
Exhibit A-48 (HAB-3)	Projected Capital Expenditures Environmental - 316(b) Compliance Summary of Actual and Projected Electric Capital Expenditures; and

Exhibit A-49 (HAB-4) Projected Capital Expenditures Environmental – SEEG Compliance Summary of Actual and Projected Electric Capital Expenditures.

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

A. Yes.

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 regulations intended to reduce the emission of air contaminants. In addition to air regulations, there are also a number of additional environmental regulations related to water and waste regulation. The Company is seeking recovery of costs incurred for compliance with the following regulations:

Air Quality Regulations

	Regulation	Acronym	Controlled Pollutant	Compliance Date
a.	Cross-State Air Pollution Rule	CSAPR	NOx, SO_2	2015
b.	Mercury Air Toxics Standards	MATS	Hg, PM, Acid Gases, Metals	2015*
c.	Michigan Mercury Rule	MMR	Hg	2015*

*Compliance is 2016 with a one-year extension from the 2015 deadline.

Water Quality Regulations

	Regulation	Acronym	Controlled Pollutant	Compliance Date
d.	Clean Water Act §316(b)	316(b)	Fish Protection	T.B.D
e.	Steam Electric Effluent Guidelines	SEEG	Effluent	2020-2023

Coal Combustion Residuals (Waste) Regulations

	Regulation	Acronym	Controlled Pollutant	Compliance Date
f.	Resource Conservation Recovery Act	RCRA	Coal Combustion By-Product	2018

Environmental Regulations – Air Quality

Q. Can you please describe the Cross State Air Pollution Rule ("CSAPR")?

A. CSAPR is a cap and trade rule much like the Clean Air Interstate Rule. CSAPR governs the emission of sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") from fossil-fueled EGUs through the use of an allowance based "cap and trade" program, except that it restricts interstate trading for use only for addressing relatively small changes in year-to-year emissions variability. Under this program, NO_x is regulated on both an annual basis and during the ozone season (May through September). Each allowance (annual or ozone) permits the emission of one ton of NO_x, with the emissions cap and number of allocated allowances decreasing over time. SO_2 is regulated on an annual basis only, with the emissions cap decreasing over time. Phase I was effective from January 1, 2015 through December 31, 2016 and Phase II became effective on January 1, 2017.

Q. Can you please describe the Mercury and Air Toxics Standards ("MATS")?

A. MATS is a federal rule that was finalized by the Environmental Protection Agency ("EPA") in December 2011 and regulates emissions of mercury, acid gases, certain metals, and organic constituents via emission rate limits or the use of work practices for coal- and oil-fired EGUs. Unlike prior regulations allowing allowance purchases or emission averaging over multiple units, MATS require unit-by-unit control equipment. Compliance with MATS was required by April 16, 2015. However, the Company received an extension from Michigan's Department of Environment, Great Lakes & Energy ("EGLE", formerly Michigan Department of Environmental Quality (MDEQ)) which pushed compliance to April 16, 2016. Consumers Energy has five coal-fired units and two oil-fired units subject to MATS.

Q. Can you please describe the Michigan Mercury Rule ("MMR")?

A. The purpose of the MMR is to regulate the emissions of mercury in the state of Michigan. Existing coal-fired EGUs must choose one of three methods to comply with the emission limits and any new EGU will be required to utilize Best Available Control Technology. Initial compliance with MMR was January 1, 2015. However, in response to the Office of Regulatory Reform Recommendation A-2, EGLE revised the MMR in October of 2013 to align the compliance deadline to the MATS' required compliance date. In addition, EGLE issued variances for compliance requirements under MMR and also indicated that construction extensions granted via the MATS process would also cover MMR related requirements. Therefore, the effective date of compliance with MMR was April 16, 2016.

Q. Please describe what regulations EGUs face regarding greenhouse gases.

A. On June 19, 2019, EPA finalized three rulemakings: (i) repeal of the Clean Power Plan; (ii) issuance of the final Affordable Clean Energy ("ACE") Rule and; (iii) issuance of new Clean Air Act ("CAA") Section 111(d) regulations.

Under the ACE Rule, states must develop, submit, and implement approved plans that establish standards of performance to meet emission guidelines for carbon dioxide (CO_2) reductions from existing coal-fired EGUs. The issuance of the new CAA §111(d) regulation provides timing and requirements for EPA and state implementation actions under ACE. The rule package was published in the Federal Register on July 8, 2019, thus making the effective date of the rules September 6, 2019.

Consumers Energy cannot predict the outcome of these EPA rules in court or the effect of the Trump administration on the EPA rules, but will continue to monitor regulatory activity, both at the state and federal level, regarding greenhouse gas emissions standards that may affect EGUs. As a result, the Company is not seeking recovery, as a part of this filing, for any expenditure related to greenhouse gas emissions compliance as it currently has none identified for its existing fleet of generating units.

<u>Air Quality Compliance Strategy</u>

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

A. Cost recovery reflecting the Company's AQCS was approved in the November 19, 2015 Order in the Company's 2014 Electric Rate case, MPSC Case No. U-17735. This AQCS has prudently ensured compliance with applicable state and federal environmental 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 Michigan-based coal generation.

Q. What are the capital investments the Company is seeking recovery of in this case that are specifically related to air quality control?

A. As shown in Exhibit A-46 (HAB-1), the Company has completed the installation of the entire suite of AQCS projects. There are no additional AQCS projected expenditures in the test year of this case.

<u>Environmental Regulations and Compliance Strategy – Waste</u>

Q. Can you please describe the relevant parts of the RCRA as related to Coal Combustion Residual ("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 new 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 despite existing state rules or adaptation of state rules to encompass new standards. 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. This bill provides authority for state implementation of coal ash management through a state permit program in lieu of the current enforcement of the CCR Rule through the RCRA Citizen Suit Authority. States may elect to submit a CCR permit program to the EPA for approval. The State of Michigan passed rules in late 2018 outlining a state permitting program and is currently awaiting sign-off from the Attorney General's Office prior to submitting it to EPA for approval. In the interim, EPA has enforcement authority over the RCRA-CCR Rule as provided in the WIIN Act.

Q. How does Consumers Energy intend to comply with management of CCRs under the RCRA?

A. The current strategy implemented the bulk of these requirements by the end of 2019 to comply with RCRA deadlines.

With the passage of the WIIN Act, and subsequent discussions with EGLE on a potential state program, there exists a high likelihood that the State of Michigan will apply to the EPA for approval of a state CCR permitting program in 2020. The existence of a state permitting program would allow EGLE to issue permits under Michigan's solid waste management law (Part 115 of the Natural Resources and Protection Act of 1994 ("NREPA"), as amended) and in surface impoundments (via Part 31 of NREPA) to regulate compliance schedules and activities for CCR landfills and surface impoundments in lieu of self-implementing compliance activities. State CCR permitting programs must be approved by the EPA on the basis that they are "as protective as" the CCR Rule. Thus, similar compliance standards will be required within the state permitting program, including requirements to make compliance documentation publicly available, completing the work, and then self-reporting by providing notifications to EGLE and posting to a publicly accessible compliance website. In addition to installing an engineered double-lined impoundment in 2018 to replace the current earthen dike impoundment, the D.E. Karn ("Karn") landfill completed closure and placement of the final cover system in 2019.

The J.C. Weadock ("Weadock") landfill will continue to operate for the life of the Karn facility. As a result of the RCRA Rule, beginning in 2015, and continuing through 2016, efforts commenced to remove wastewater conveyances from the landfill, followed by grading to promote drainage to ditches. This work included modifying the existing outlet structure and systematically draining ponded water out of low areas. The modifications of the existing outlet structure allow for gravity drainage of the interior of the disposal area, thus minimizing groundwater infiltration to the landfill and improving the subgrade to place the final cover upon construction. In 2018 the installation of a soil-bentonite slurry wall at the Weadock landfill was completed in order to fully enclose the waste footprint. Completing the construction of the slurry wall eliminates the passive "vent" to the discharge channel and provides containment of CCR materials as well as controls for potential sources of groundwater impacts.

In 2017, the J.H. Campbell ("Campbell") facility completed construction to replace unlined bottom ash ponds with concrete tanks. As a result, unlined bottom ash ponds have been closed, the units are continuing to wet sluice bottom ash to the concrete tanks, and ground water protection has been greatly enhanced while maintaining the ability to beneficially use the bottom ash.

Q. What are the capital investments Consumers Energy is seeking recovery of in this case that are specifically related to RCRA compliance?

A. As shown on Exhibit A-47 (HAB-2), Consumers Energy has completed the capital investments necessary for compliance with RCRA prior to the test year of this case. There are additional closure activities that will continue throughout the test year and beyond; however, those expenses are Cost of Removal and are not included in this filing.

<u>Environmental Regulations and Compliance Strategy – Water</u>

Q. Can you please describe the CWA Section 316(b)?

A. On August 15, 2014, the EPA published the Final Section 316(b) Rule ("Final Rule") in the Federal Register, establishing new standards for Cooling Water Intake Structures ("CWIS"). The Final Rule became effective on October 14, 2014 and requires existing power generation facilities with a design intake flow greater than two Million Gallons per Day ("mgd") from waters of the United States for cooling to reduce impingement and entrainment of fish and other aquatic organisms at CWIS. Additionally, any facility subject to the Final Rule with actual flows in excess of 125 mgd was required to provide an entrainment study with its National Pollutant Discharge System ("NPDES") permit application. As such, the Final Rule applies to all of Consumers Energy's base-load generation facilities.

The Final Rule establishes national requirements which apply to the location, design, construction, and capacity of CWIS and requires the use of Best Technology Available ("BTA") for minimizing adverse environmental impact. For impingement, the EPA has determined the BTA to be modified traveling screens, with fish return systems. However, six additional alternatives, with equal or better performance, are available for a facility to meet this standard. For entrainment, the EPA did not determine a BTA, because no one technology can be universally employed at all facilities. Rather, entrainment BTA is determined on a site-specific basis by the regulatory agency responsible for administering the NPDES Program. The site-specific controls are justified through a series of prescribed studies including, but not limited to: (i) entrainment characterization; (ii) technical feasibility and cost evaluation; (iii) benefits valuations; (iv) non-water quality and other environmental impacts; and (v) peer review. For the Campbell and Karn facilities, these prescribed studies were completed in 2017. Several of those studies required peer review, which were completed in the first quarter of 2018 prior to submittal to EGLE in Q2 2018.

Q. How does Consumers Energy intend to comply with the CWA Section 316(b)?

A. To demonstrate compliance with impingement and entrainment standards, it is projected that the EGLE may require Campbell Units 1 and 2, to make intake modifications. Preliminary evaluation suggests modifying the deep-water intake for Campbell Unit 3 to accommodate intake for Units 1 and 2 has the potential for significant cost savings and environmental benefits over installing fine mesh screens at the Campbell Unit 1 and 2 intake. Campbell Unit 3 will likely require no new controls as its existing offshore wedge wire screen intake is sufficient. At Karn, Units 1 and 2 will be ceasing operation in accordance with the IRP and will not require further controls. Karn Units 3 and 4 will likely require no new controls as their existing cooling towers are sufficient.

The prescribed studies and associated BTA demonstrations for Campbell were to be submitted to the EGLE by the NPDES permit application, which was due April 4, 2016; however, the Company petitioned, and the EGLE accepted, the proposal to submit information by April 30, 2018. In the Company's submittal, we are seeking compliance for the entire Campbell complex rather than individual cooling water intake structures. For entrainment, we have proposed to the EGLE that the existing cooling water intake systems be considered BTA since the costs of technologies are wholly disproportionate to the benefits. In regard to impingement, we are advocating that BTA at the Campbell complex is met through de minimis rate of impingement. EGLE's final determination on BTA was expected in 2019, with an assumed operational compliance date by year-end 2023, but we have not received any response from EGLE yet. A determination is now expected in 2020. Also, the 2023 compliance date depends on the State's timely issuance of the final NPDES permit, the particular site-specific controls/technologies ultimately determined to be BTA, and the negotiation of appropriate timelines in the NPDES permitting process for the Campbell generating complex. Both the timing and the actual BTA determination from the EGLE are uncertain. As previously stated, the cost-benefit analysis, which was included in the regulatory submittal package, suggests that the cost of entrainment technologies outweighs the benefits to the fishery, but that does not preclude the EGLE from requiring one for BTA. However, if the EGLE agrees that the existing cooling water intake at Campbell is sufficient, then they may require the Company to conduct further studies to evaluate impingement.

Q. Are there other water related regulations to which Consumers Energy's facilities are subject?

A. Yes. On November 3, 2015, the EPA published the final Effluent Limitation Guidelines Rule for the Steam Electric Power Generating Point Source Category (referred to as "SEEG") into the Federal Register. The final SEEG Rule establishes effluent limitations based on Best Available Technology Economically Achievable ("BAT") for existing sources. The final SEEG Rule excludes oil-fired generation units and units with a nameplate capacity of 50 MW or less. The final SEEG Rule also establishes New Source Performance Standards and Pretreatment Standards for Existing and New Sources that discharge to Publicly Owned Treatment Works.

On September 18, 2017, the EPA published into the Federal Register its intent to conduct a rulemaking to potentially revise certain BAT effluent limitations and Pretreatment Standards for Existing Sources ("PSES") for the steam electric power generating point source category. As a result, the EPA postponed the earliest compliance dates for the new, more stringent, BAT effluent limitations and PSES for Flue Gas Desulfurization ("FGD") wastewater and bottom ash transport water for a period of two years from 2018 to 2020. The EPA's action to postpone certain compliance dates was intended to preserve the status quo for FGD wastewater and bottom ash transport water until the EPA completed its next rulemaking concerning those waste streams, and it thus did not otherwise amend the effluent limitations guidelines and standards for the steam electric power generating point source category.

On November 22, 2019, the EPA published a proposed revision to the SEEG rule. EPA is proposing to revise its technology-based effluent limitation guidelines applicable to FGD wastewater and Bottom Ash ("BA") transport water, but not other waste streams covered by the 2015 rule. For purposes of this testimony only BA transport water requirements will be discussed, as Consumers Energy does not have any FGD wastewater streams.

This proposed rule identifies treatment using high recycle rate systems or dry handling as the BAT basis for control of pollutants discharged in BA transport water. According to EPA, a high recycle rate system is a recirculating wet ash handling system operated such that it periodically discharges (purges) a small portion of the process wastewater from the system. EPA has found that this technology is available and economically achievable. In contrast to the 2015 rule, which required a zero-liquid discharge, the proposed rule allows facilities with a wet ash handling system to discharge up to 10 percent of the primary active wetted bottom ash system volume on a 30-day rolling average under certain conditions. As a result, Consumers Energy does not anticipate significant changes to our compliance strategy beyond adjusting our engineering designs from a zero discharge system to a high recycle rate system.

Q. What BAT technologies have been defined for each waste stream?

A. The final SEEG Rule, in addition to already regulating effluent limitations for several waste streams (such as low volume wastewaters), establishes BAT model technologies for the following waste streams:

Waste Stream	Existing Source BAT Model Technology
FGD Wastewater*	Chemical Precipitation + Biological Treatment
Fly Ash Transport Water*	Dry handling
Bottom Ash Transport Water	Dry handling/Closed loop
Combustion Residual Leachate	Impoundment (Equal to existing BPT)
FGMC Wastewater*	Dry handling
Gasification Wastewater*	Evaporation
Nonchemical Metal Cleaning Wastes	No technology chosen – BAT for nonchemical metal cleaning wastewater is reserved.

Note: * These waste streams are not generated at the Campbell or Karn facilities.

Existing source BAT effluent limitations for waste streams present at Consumers Energy facilities are summarized below:

Waste stream	Present At	Existing Source BAT Effluent Limitations
Bottom Ash Transport Water	Campbell Karn	No discharge of pollutants, including if transport water is used in other plant process or is sent to a treatment system. Exception for reuse in FGD scrubber. Low volume, short duration discharges from minor leaks or minor maintenance events is allowed.
Combustion Residual Leachate	Campbell	TSS Daily Max. = 100 mg/L TSS Monthly Avg. = 30 mg/L
Nonchemical Metal Cleaning Wastes	Campbell Karn	Reserved. No federal limits established. The EPA expects the permitting authority to examine the historical permitting record to determine how discharges of this waste stream should be permitted.

Q. What are the applicability dates for SEEG?

A. Compliance with new BAT limitations does not apply until a date determined by the permitting authority that is "as soon as possible" beginning November 1, 2020, but no later than December 31, 2023. The "as soon as possible" date determined may or may not be the same for each waste stream. The current SEEG compliance strategy is to plan for full compliance by year-end 2023, which is consistent with the timing of the current rule and the proposed revision and our NPDES permits, which incorporate site-specific SEEG requirements.

Q. How does Consumers Energy intend to comply with SEEG?

A. At Campbell and Karn, the RCRA-CCR Rule requires unlined bottom ash ponds not meeting performance standards to cease accepting CCR in 2018. As a result, Consumers Energy has replaced the unlined bottom ash ponds with concrete tanks at Campbell and a double-lined pond at Karn and continues wet sluicing bottom ash. Per the 2015 SEEG Rule, the transport water will need to be managed in a closed loop system and not discharged. A blow-down stream will need to be treated and returned to the closed loop system or disposed of in a terminal process to manage the expected eventual build-up of suspended and dissolved solids. While the concrete tanks were constructed in 2017 and the double-lined ponds in 2018, the closed loop systems will likely not be constructed until the 2022 through 2023 timeframe to accommodate reissuance of NPDES permits and any regulatory changes from the EPA as previously discussed.

At Campbell, low volume wastewaters and other non-bottom ash transport process water streams currently flowing to the bottom ash ponds will be segregated from the bottom ash system and treated in new lined impoundments and oil/water separators (to remove suspended solids and oil and grease). Post treatment, these waste streams will be discharged to the Campbell Unit 3 intake canal for subsequent reuse in the cooling water or house service water systems (referred to as a multi-stream reuse system) or potentially used as make up in the Spray Dry Absorber raw water feed system, where it would be consumed entirely, without discharge. Coal pile runoff water currently drains to the bottom ash pond/ditch system. In 2016 through 2017, coal pile runoff modifications were completed to ensure the discharge quality of this waste stream. Upon approval from EGLE, the coal pile runoff water will be retained in an expanded detention basin, and if necessary, receive further treatment to remove total suspended solids and discharged to the Campbell Units 1 and 2 intake canal for subsequent reuse. No change to the management of the combustion residual leachate system is planned.

Karn Units 1 and 2 will cease operation prior to the required compliance deadline and therefore not affected by SEEG.

Q. What are the capital investments Consumers Energy is seeking recovery of in this case that are specifically related to Section 316(b) and SEEG compliance?

A. As previously stated, a BTA determination for compliance with Section 316(b) is now anticipated in 2020. The requested test year dollars position us well to be able to react to the EGLE's final Section 316(b) BTA determination. If entrainment BTA is required then we will move forward with the design and engineering of an alternate intake structure for Campbell Units 1 and 2. If the EGLE agrees that the existing cooling water intake at Campbell is sufficient and they require us to then evaluate impingement, the requested test year dollars will then be spent on impingement studies on both units intakes. See Exhibit A-48 (HAB-3) for Section 316(b) capital expenditures.

For SEEG compliance, the Company will be moving forward with additional waste water studies in 2020 to determine the level of required waste water treatment at the Campbell site. In the test year we will then design, engineer, and begin procurement for Campbell's closed loop system and waste water treatment. See Exhibit A-49 (HAB-4) for SEEG capital expenditures.

<u>**Environmental Capital Investment Summary**</u>

Q. Describe how Consumers Energy's overall environmental compliance plan for air, water, and waste provides value to customers.

A. The Company's approach has considered: (i) a variety of technologies; (ii) deferral of expenditures for as long as possible consistent with the applicable rules; (iii) risks associated with relying on and use of emission allowance purchases; and (iv) the wisdom of retrofitting older, smaller generating units.

Regarding water, the projected SEEG and §316(b) expenditures in this case have been minimized to the greatest extent possible to allow time for the 316(b) BTA determinations, new SEEG rulemaking, and to accommodate RCRA rule related requirements, all without compromising the schedules for compliance with both water-related regulations.

Regarding waste, the Company has taken a prudent and proactive approach to RCRA compliance. Each CCR site must perform significant ground water monitoring and meet drinking water standards. The ash ponds at both the Campbell and Karn sites were defined as "unlined CCR Surface Impoundments" under the RCRA-CCR Rule. As such, those impoundments are subject to the forced closure provisions under 40 CFR 257.101 which requires cessation of placement of CCR and non-CCR wastewaters and initiation of closure of unlined surface impoundments within six months of discovering they do not meet the following standards of the RCRA-CCR Rule:

i. Factor of Safety Analysis;

ii. Groundwater Performance Standard; and

iii. Location restrictions.

The Company elected to pro-actively replace the unlined bottom ash ponds with concrete tanks at Campbell and a double-lined pond at Karn and to continue wet sluicing bottom ash.

Q. How has Consumers Energy ensured that the costs associated with the installation of pollution control equipment, for the various environmental regulations, are reasonable and prudent?

A. Consumers Energy ensures that the costs for pollution control equipment are reasonable and prudent in several different ways:

1. Technology evaluations are performed to select the least cost solution.
2. Competitive bidding or vendor alliance agreements are used for projects of this magnitude. Bids are awarded on the basis of total evaluated cost which includes conformance to design specifications, service requirements, delivery requirements, past performance, price, product maintenance and operating costs, servicing, terms of payment, commercial and contract terms and conditions, and other applicable factors.
3. Our contracting strategy incorporates the following principles:
    a. Project Specific Procurement Plans to identify how each project will be optimally procured. Our overall strategy is to buy/contract in the vendor's and contractor's core competencies. This helps to keep contract issues to a minimum.
    b. We also look at each and every contract opportunity with a focus on how to best structure our contracts, (i.e., firm lump sum, design/build, cost reimbursable with targets and incentives, unit price, or a blend of the above). There is not a "one size fits all" approach, so we tailor each contract to manage the risk in the most efficient way.

c. We act as our own contracting entity. This eliminates mark-ups on all of the engineered equipment that we purchase. There are situations where we allow constructors to subcontract to a firm that specializes in specific areas, such as tank erection, insulation, or electrical contracting. This contracting arrangement typically results in field supervision and labor optimization, some sharing of construction equipment, and enhances the daily interface leading to a more efficient construction program.

d. We have consistently met project Key Performance Indicators for safety, quality, cost, schedule, and emission reduction on our air quality projects over the last ten years.

4. The projects are managed in accordance with the PMI's standards, which serve as the basis for our Project Management processes. Our Project Management processes fully align the PMI standards on all facets for managing large projects. Project Management processes address scope management, cost management, schedule management, quality management, contract management, risk management, communication management, stakeholder management, information management, and other critical aspects of managing a project or program. Several project team participants are certified Project Management Professionals skilled in the execution within their role on the project.

Q. Are Consumers Energy's environmental compliance plan and associated investments reasonable and prudent?

A. Yes. The Company has reasonably ensured compliance with applicable state and federal environmental regulations. The Company's investments made to achieve such compliance have been made in a manner that has minimized, to the extent reasonably possible, the associated costs for customers. The investments made ensure continued supply reliability and sustainability. They ensure sustainability by maintaining environmental compliance and achieving significant reduction of pollutants. To date, we have ensured supply reliability by allowing for the continued operation of Michigan-based coal generation, thus helping preserve the fuel diversity necessary to protect customers from significant fuel price fluctuations.

Q. How do customers benefit from the Company's sustainability efforts?

A. In the past five years, Consumers Energy has created a cleaner, more sustainable energy future for the state by taking a leadership position in reducing air emissions, reducing water usage, saving landfill space, and boosting the amount of renewable energy supplied to customers. Consumers Energy plans to meet Michigan's energy needs by reducing carbon emissions by 90% and no longer using coal to generate electricity by 2040. To meet this goal, more than 40% of the energy produced will likely come from renewable sources and energy storage by 2040. This continued transformation to cleaner fuel sources is part of a long-term strategic commitment to protect the planet.

To date, our actions have reduced our carbon intensity by more than 35%, reduced our water usage by 35%, and avoided over one million cubic yards of landfill disposal. In addition, the Company also announced five-year environmental goals in 2018 for Michigan water, waste, and land, including:

i. Water: save 1 billion gallons of water;

ii. Waste: reduce waste to landfills by 35%; and

iii. Land: enhance, restore, or protect 5,000 acres of land in Michigan.

These goals represent our further commitment to leave Michigan better than we found it.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Eugène M.J.A. Breuring, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Senior Rate Analyst II in the Planning, Budgeting & Analysis Section of the Rates & Regulation and Quality Department.

Q. Please describe your qualifications.

A. In 1992, I graduated from Grand Valley State University with a Bachelor of Business Administration in Accounting. In 1996, I graduated from Thunderbird School of Global Management with a Masters of Business Administration in International Management. I have also attended trade-specific conferences and seminars related to Michigan and United States economies, Michigan economic forecasts, as well as regression modeling.

Prior to joining Consumers Energy in 2013, I worked at the Kellogg Company, Tecumseh Products Company, and Stryker Corporation, mostly in a financial planning, budgeting, and forecasting capacity. In January of 2013, I accepted the position of Senior Rate Analyst II, which is my current position at Consumers Energy. In this capacity, I am responsible for preparing the Company's official electric deliveries (sales) and customer forecasts, sponsoring the sales and customer forecast testimony and exhibits, industry research, and various economic studies. Also, I am responsible for creating the Company's revenue forecast related to the electric business.

Q. Have you sponsored testimony in any previous cases before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I have presented the Company's electric business sales and revenues forecasts in the following cases:

U-17771	2016 – 2017 Energy Optimization Plan;
U-17990	General Electric Rate Case;
U-18142	2017 Power Supply Cost Recovery ("PSCR") Plan;
U-18231	2017 Biennial Renewable Energy Plan;
U-18261	Amended Energy Optimization Plan;
U-18322	General Electric Rate Case;
U-18402	2018 PSCR Plan;
U-20134	General Electric Rate Case;
U-20165	2018 Integrated Resource Plan ("IRP");
U-20219	2019 PSCR Plan;
U-20372	2019 Energy Waste Reduction ("EWR") Electric and Gas Biennial Plan; and
U-20525	2020 PSCR 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 testimony is to present the Company's electric revenues, deliveries, generation requirements, and peak demands for test year 2021.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am providing the following exhibits:

Exhibits	Description	
A-5 (EMB-1)	Schedule E-1	Annual Service Area Sales by Customer Major Classes and System Output (5-Year Historical);
A-15 (EMB-2)	Schedule E-1	Annual Service Area Sales by Major Customer Classes and System Output (5-Year Projected);
A-15 (EMB-3)	Schedule E-2	Test Year Total Company Electric Revenues & Deliveries;
A-15 (EMB-4)	Schedule E-3	Electric Deliveries & Customer Counts by Rate Category (Historic and Test Year);
A-15 (EMB-5)	Schedule E-4	Calculation of Annual System Load Factor (Historic and Test Year); and
A-50 (EMB-6)		Estimated Electric Rate Case PSCR Factor (Test Year).

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

A. Yes.

SECTION I. TEST YEAR ELECTRIC REVENUES

Q. Please describe Exhibit A-15 (EMB-3), Schedule E-2.

A. Exhibit A-15 (EMB-3), Schedule E-2, summarizes the component differences between the 2018 historic revenues and deliveries and the forecasted test year revenues and deliveries used in this case.

Q. Please explain the Long-Term Industrial Load Retention Rate ("LTILR") adjustment to deliveries (MWh) and revenues in Exhibit A-15 (EMB-3), Schedule E-2.

A. PA 348 of 2018 gave the Commission authority to allow customized electric rates (LTILR rates) for companies meeting certain criteria. As such, the Company is seeking the approval of an LTILR rate with one large industrial customer, Hemlock Semiconductor ("HSC"). In the test year, revenues and deliveries of HSC are excluded from base tariff revenues, as well as deliveries. Instead, projected test-year revenues of $76,105 are reflected in the Miscellaneous Revenue line in Exhibit A-15 (EMB-3), Schedule E-2 (column e, line 26). The HSC revenue calculation is covered by Company witness Michael P. Kelly. Further details regarding the LTILR rate are also covered by Company witness Kelly.

Q. Please explain the credit revenues that are included in the test-year projections as they relate to the Residential Senior Citizen ("RSC") and Residential Income-Assistance ("RIA") provisions.

A. The average test-year customer count projections for the RSC and RIA provisions are 320,504 and 45,290, respectively. These projections are based on regression modeling as explained later in this testimony, which incorporates historical trends within these customer groups. With credits of $3.75 (RSC) and $7.50 (RIA), per meter, these projected customer counts generate revenue credits of $14.4 million of annual credit revenues for the RSC provision and $4.1 million for the RIA provision.

The associated reduction in base tariff revenues is reflected in Exhibit A-15 (EMB-3), Schedule E-2, column (l), line 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.

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 ("HDD") and Cooling Degree Days ("CDD") in the econometric models.

Q. What are econometrics or econometric techniques?

A. These are quantitative economic statistical techniques or tools that model the economy using mathematical and statistical relationships. A basic tool for econometrics is the regression model, which will be discussed below.

Q. Please describe the impact of the economy on the forecasting process and the assumptions you made regarding these variables in the forecast.

A. The Company uses economic indicators to capture the growth expectations related to increased economic activity in its service territory. Primarily, this includes employment and industrial production forecasts provided by IHS Markit, a leading publishing company that provides industry-specific data and analyses.

Q. Please describe the impact of demographics on the forecasting process.

A. Population projections are used in the development of the long-term customer forecast. In particular, the forecast of residential customers is derived from the county-level population projections provided by IHS Markit.

SECTION III. 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 to forecast electric deliveries and peak demand for the Company's electric service territory was used.

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 temporal cycles, and daily temperature information. Most observations are entered directly into the modeling framework as dependent and explanatory variables. The daily temperature information, however, is transformed to monthly HDD and CDD variables prior to entering the modeling framework. The second step is importing the economic and demographic variables from IHS Markit into the sales modeling framework. The third step is importing electric use forecasts for wholesale, electric vehicles, polycrystalline production, and energy savings from the Company's EWR programs. These forecasts are exogenous to the modeling framework and were either adopted by the Commission in prior electric rate cases, reflect current industry expectations, or are based on end-use analyses. The fourth step is reviewing the imported observations to identify data issues before running the econometric models. In situations when erroneous data is observed, it is either corrected where possible or removed from the models. The fifth step is executing the regression functions and reviewing the corresponding statistical metrics. The final step in the sales forecasting process is to combine the regression forecasts with the external forecasts imported in step three.

Q. What is the process involved in developing the electric peak demand forecast?

A. The peak demand forecast process is similar to that of the electric delivery forecast. The first step in the peak demand forecast is importing the Company's monthly system peak demands, corresponding minimum and maximum daily temperature, forecasted base electric deliveries, seasonal binaries, and number of customers into the demand modeling framework. A weighted sum of the minimum and maximum temperatures is used to develop the peak CDD and HDD variables prior to importing into the model framework. The second step is reviewing the imported observations to identify data issues before executing the peak demand econometric model. The third step is regressing the observed peak demands against the seasonal binary, degree day, and forecasted base electric sales. The final step in the peak demand forecasting process is combining the results of the econometric model with the planned peak reductions from the Company's direct control and Peak Time-of-Use ("PTOU") programs.

Q. In utilizing the regression models, what evaluation process is followed to ensure that the models' results are satisfactory?

A. Regression modeling is used to develop the electric deliveries and customer count forecast models based on weather and economic variables. Each model is selected based on its ability to properly explain variation in historical data – i.e., how well it fits the data – along with the statistical significance of the model coefficients. Particularly, regression model performance is evaluated based on the adjusted coefficient of multiple determination ("R_a^2") and Mean Absolute Percent Error ("MAPE").

Q. Please explain the use of R_a^2 and MAPE.

A. Both of these statistical tests are used to evaluate how well the models fit the historical data, and also provide a good indication of how well the models will perform in the forecast period. The R_a^2 measures the ability of the models to explain variations in the historical data. An R_a^2 of unity suggests that a model explains all of the variations in the data whereas an R_a^2 of zero suggests it explains none of the variations. For example, if regression models have R_a^2 values above 0.9, this suggests that at least 90% of the variation in the data is explained by the models. In most cases, the models used in the Company's forecasting process have values between 0.90 and 0.97. In addition, to gauge overall model performance, the MAPE values are considered. Essentially, the MAPE is used to measure the model errors in which smaller values suggest better model performance. MAPE values of less than 3% are generally considered ideal, although higher values may also be deemed acceptable based on other considerations, such as the R_a^2. The regression models used in the Company's forecasting process generally have MAPE values between 0.2% and 2.1%.

Q. Please explain the criteria used when considering the t-statistics and p-values associated with the model coefficients.

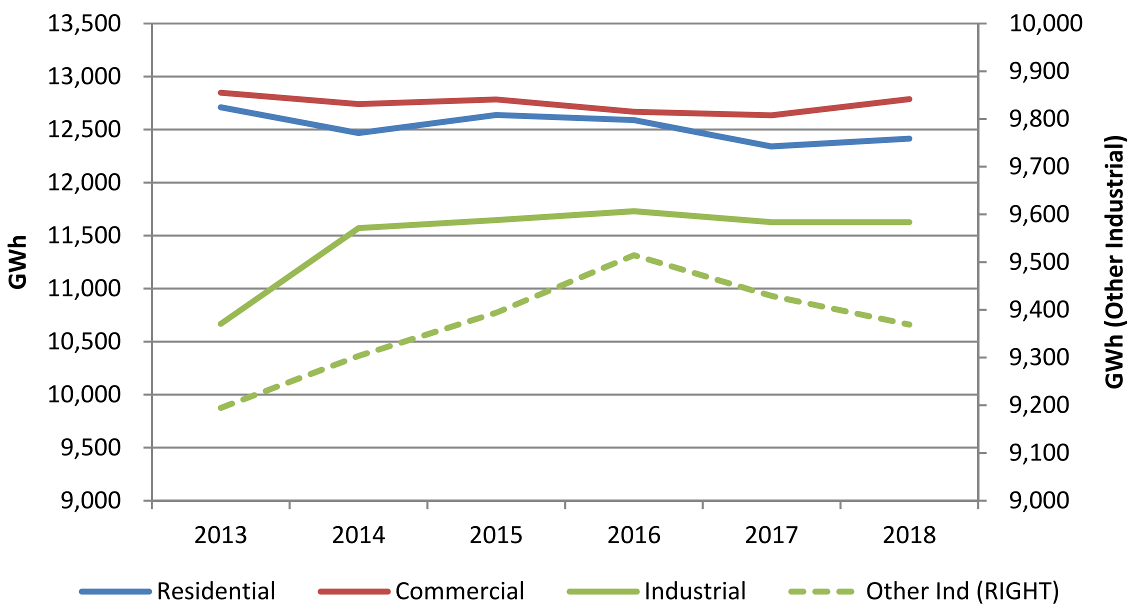
A. Regression analysis is used to develop models that minimize the variance between the actual data and estimates from the models based on the relationship between dependent and independent variables. A numerical coefficient ("β") is estimated for each independent variable in the model and represents the best linear unbiased estimate for that variable's contribution toward explaining the dependent variable. The t-statistics and p-values are used to gauge the relevance of each independent variable in the model. The t-statistic and p-values measure the statistical significance of including a particular independent variable based on a probability distribution. A t-statistic above two and p-value below 5% for a particular β suggests the independent variable is statistically significant and is appropriate to include in the regression model. Independent variables with t-statistics below two and p-values above 5% suggest the variable should be excluded from the model since it does little to explain the dependent variable. In addition, the direction (positive or negative coefficient sign) and magnitude of each coefficient are also considered when determining whether to include or exclude variables from the models. The models' independent variable t-statistics and p-values are within these ranges and are, therefore, considered relevant.

SECTION IV. HISTORICAL AND FORECASTED ELECTRIC DELIVERIES

Q. Please explain the Company's historical levels of electric deliveries for the five-year period from 2013 to 2018.

A. In the past five years, weather-normalized electric deliveries increased at a 0.3% Compound Annual Growth Rate ("CAGR") from 2013 to 2018, with most of the observed gain occurring in the industrial class (1.7% for the same period) as shown in Figure 1.

Figure 1 - Historical Electric Cycle-billed, Weather-adjusted Deliveries by Class



Q. What is the cause of the decrease in weather-normalized residential and commercial deliveries from 2012 to 2017 in the Company's service territory?

A. In large part, the retraction in the residential and commercial sectors is caused by a nearly flat population growth in the electric service territory during this period, coupled with increased EWR efforts, starting in 2008.

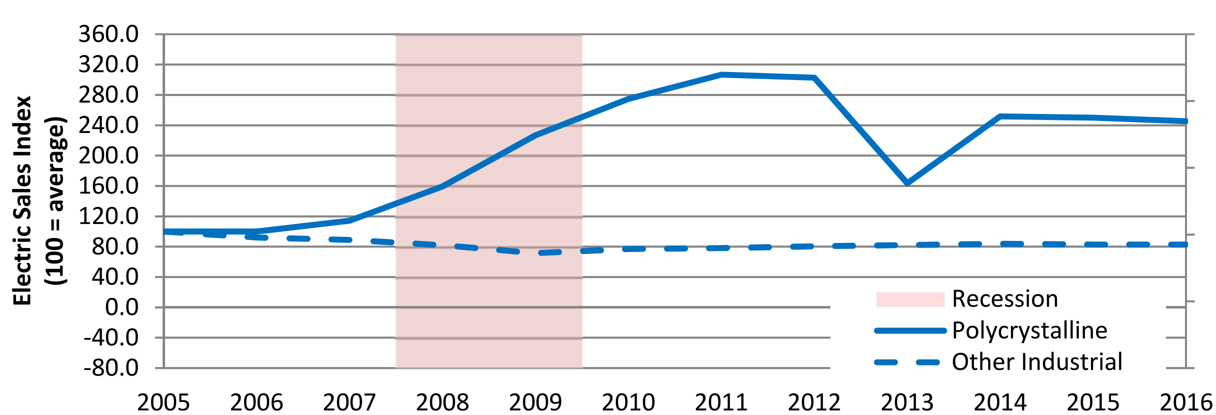
Q. Was there a similar decrease in industrial deliveries in the Company's service territory from 2012 to 2017?

A. No. There was a pronounced decrease in industrial sales in 2013 and a subsequent bounce-back in 2014 to 2016.

Q. To what do you attribute the sudden decrease and rebound in industrial sales from 2013 to 2016?

A. Following the 2008 recession, industrial electric deliveries increased 5.2% per year from 2009 to 2012. However, the increase is not homogeneous across all sectors in the class. As shown in Figure 2, electric deliveries grew precipitously in polycrystalline manufacturing until 2012. The sudden decrease in 2013 is attributed to international trade restrictions imposed by East Asian countries. Since 2013, the polycrystalline production has picked up world-wide, as evidenced in Figure 2. While the polycrystalline industry was booming, the other industrial sectors exhibited only moderate growth in electric deliveries. Indeed, from the start of the recession in 2007 until 2016, electric deliveries in the other industrial sector decreased 0.8% per year while increasing 8.9% per year in the polycrystalline industry.

Figure 2 - Industrial Electric Sales - Consumers Energy



Q. What are the electric delivery expectations for the test year used in this case?

A. Total electric deliveries are expected to decrease 1.4 percent per year from the historic year 2018 to the 2021 test year. The rate category level results are shown in Exhibit A-15 (EMB-4) Schedule E-3. The historic annual class level results for 2014 through 2018 are shown in Exhibit A-5 (EMB-1), Schedule E-1, while the projected annual class level results for 2019 through 2023 are shown in Exhibit A-15 (EMB-2), Schedule E-1.

Q. Exhibit A-15 (EMB-4), Schedule E-3, shows annual deliveries reducing from 38,231 GWh in 2018 to 34,511 GWh in the 2021 test year. This is more of a decrease in deliveries than the 1.4% decrease as explained above. Why?

A. The test year (2021) excludes the large industrial customer deliveries related to LTILR as explained earlier in this testimony. Excluding these deliveries from historical 2018 Primary Demand GPD deliveries (2,257 GWh), provides a CAGR of -1.4% from 2018 to 2021.

Q. Beginning in 2020, the residential rate structure has incorporated the new rate groups Nighttime Savers ("RPM"), Summer On-Peak ("RSP"), and Smart Hours ("RSH"). Why are there still customers projected in the original Standard Service ("RS"), as shown in Exhibit A-15 (EMB-4), Schedule E-3, line 1, column (c) and (d)?

A. As of January 1, 2020, the RS rate is closed to new business and this rate will only be available to customers electing a Non-Transmitting Meter Provision. In the test year, the Company projects that there will be 9,621 customers electing this provision. Additionally, an estimated 6,600 customers will be on this non-transmittal rate due to their remote locations impacting the effectiveness of the Smart Meter. In the test year, a total of 16,221 customers will be projected to be on the original Standard Service rate.

Q. To what extent has the Company reflected future EWR in the electric deliveries forecast you are sponsoring in this case?

A. The Company was required under the 2008 Energy Law, Public Act ("PA") 295, to help its electric customers reduce their energy usage by at least one percent per year. In 2016, State lawmakers reinforced the use of demand-side resources, such as EWR, by amending the law to encourage utilities to expand the use of demand-side resources beyond the mandated floors. The Governor signed the 2016 Energy Laws, PA 341 and 342, on December 21, 2016. Although the Company is still required to help its customers reduce energy waste by at least one percent per year under the law, it is also encouraged to cost-effectively expand its use of demand-side resources. As such, the Company has updated the electric deliveries forecast based on the Company's commitment to help customers reduce energy waste by at least 1.5 percent per year beginning in 2017.

Q. What level of EWR savings is included in the test-year deliveries?

A. EWR savings have continued to be around 1.5% through the year 2019. From 2020 to 2023, the Company is expected to grow EWR savings to 2%, as filed in the IRP, Case No. U-20165. At the test-year, the Company's projected EWR savings is 2%.

Q. Are these EWR savings spread evenly across all of the Company's customer classes?

A. No, although the overall savings percentage is 2% by the test year, these EWR savings are expected to be allocated at 1.2% in the Residential customer class, and 2.4% in the Commercial/Industrial customer classes. These projected EWR savings are aligned with the latest-approved Company EWR plan filing with the Commission, Case No. U-18261.

Q. Please describe the process used to determine the Company's total generation requirements.

A. Per the 2018 System Loss Study, the forecasted total electric deliveries are increased by a line loss factor of 7.73 percent to determine 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 2018 System Loss Study the latest available?

A. Yes.

Q. Please explain Exhibit A-50 (EMB-6).

A. Exhibit A-50 (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, when weather-normal peak demand retracted by 4.3 percent. Looking forward, peak demand is expected to decrease 1.8% per year from 2018 to 2023. The monthly system level results of the electric peak demand forecast process is shown in Exhibit A-15 (EMB-5), Schedule E-4.

Q. Please explain the impact to the peak demand forecast from the Company's future Smart Energy programs.

A. The peak demand forecast is reduced by approximately 141 MW in 2019 and increasing to 393 MW by 2023 for the Company's AC Peak Cycling ("ACPC") Program. For the PTOU programs, peak demand is reduced by 13 MW in 2019 and increasing to 31 MW in 2023. For the test year, the total demand response for these two programs is approximately 340 MW. These programs are being implemented as part of the Company's smart energy infrastructure investments in which customers are provided technology and information to better manage their impact on the Company's system.

Q. Are there any other adjustments to peak demand?

A. Yes. In 2019, EWR and Conservation Voltage Reduction ("CVR") measures are estimated to reduce peak demand by 548 MW and 2 MW, respectively. This cumulative reduction to peak demand is projected to increase to 678 MW (EWR) and 36 MW (CVR) in the test year.

Q. To what extent is the Company's new RSP rate expected to impact peak demand?

A. The newly introduced RSP is expected to reduce the Company's peak demand by approximately 119 MW in the test year.

Q. How did the Company derive at this RSP demand reduction?

A. During the summer of 2019, the Company had an RSP pilot program in place with approximately 48,000 residential customers. This pilot group exhibited behavior that shifted an average of 3.5% load from the on-peak hours (2PM to 7PM) to the off-peak hours (7PM to 2PM) in the month of July.

Q. Across the separate demand reduction programs, what is the total adjustment to peak demand in the test year?

A. The total demand reductions to peak demand amounts to 1173 MW in the test year. (see table below)

	Demand Reductions (in MW)					
Year	ACPC	PTOU	EWR	CVR	STOU	**TOTAL**
2019	141	13	548	2	0	**704**
2020	244	17	624	18	119	**1022**
2021 *(test-year)*	319	21	678	36	119	**1173**
2022	364	24	736	48	119	**1291**
2023	393	31	775	72	119	**1390**

Q. Please explain the process used to identify the peak demand impacts of the Company's Smart Energy and EWR programs.

A. The Company developed hourly load profiles for the Smart Energy and EWR programs. The monthly energy savings associated with each of these programs are integrated with the corresponding load shape to develop hourly demand savings curves.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

LORA B. CHRISTOPHER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Lora B. Christopher, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. What is your current position with Consumers Energy?

A. I am currently the Director of Employee Benefits.

Q. What are your responsibilities as Director of Employee Benefits?

A. I am responsible for design, implementation, and administration of the Company's retirement and insurance benefit plans for employees and retirees.

In the retirement benefits area, the Company contributes to the cost of the Pension Plans, the Defined Company Contribution Plan ("DCCP"), and the 401(k) Employees' Savings Plan ("ESP"). My responsibilities for these benefit plans include the design, review, and administration of competitive, cost-effective, quality plans that will attract and retain qualified employees to serve customers. The purpose of these plans is to provide a portion of an employee's retirement income along with the employee's social security benefits and personal savings.

In the insurance benefits area, the Company contributes to the cost of these insurance benefits plans – health care (medical/prescription drug/dental including Health Savings Accounts ("HSA") and Health Care Flexible Spending Accounts ("HCFSAs")), life insurance, and Long-Term Disability ("LTD") insurance. Like the retirement plans, my responsibilities for these health care and insurance benefit plans include the design, review, and administration of competitive, cost-effective, quality plans for employees and retirees of the Company that help attract and retain qualified employees to serve customers. In addition to these plans, I have responsibility for several additional benefit plans offered to employees by the Company at group discounted rates, which require the employee to pay the full cost of the coverage elected. These voluntary plans include accidental death and dismemberment insurance (formerly known as 24 Hour Accident), health care and dependent care flexible spending accounts, vision insurance, and dependent term life insurance. These insurance benefit plans also help attract and retain qualified employees to serve customers as these plans help protect employees and their families from significant financial loss in a number of areas. Also, I have responsibility for the administration of the Company's absence management, educational assistance, and employee assistance service programs, as well as workers' compensation. Finally, I manage a total well-being program, Live Well 365, which motivates employees to manage their entire well-being.

Q. What is your formal educational experience?

A. In 2002, I graduated from Western Michigan University in Kalamazoo with a Bachelor of Business Administration degree. In 2008, I graduated from Central Michigan University earning a Master of Science in Administration with a concentration in Human Resources Management. I hold a Professional in Human Resources from HR Certificate Institute.

Q. Would you please describe your previous work experience?

A. In 2004, I began my career focused on employee benefits at CoStaff Services Professional Employer Organization ("PEO") as a Human Resources Specialist. This was a specialized role, offering independent work responsibility for administration of health insurance plans for over 50 PEO clients including plan design, enrollment administration, claim payments, audits, and COBRA administration. Also, I was responsible for absence management and workers' compensation for my clients.

In 2006, I began working for Comerica Bank as a Benefits Specialist. I was heavily involved in the benefit administration of their health care plans. Also, I was responsible for the absence management and workers' compensation programs. In 2008, I became Assistant Vice President of Employee Benefits/Senior Benefits Specialist. In this role, I managed health insurance plans including strategy, plan designs, market analysis, rate renewals, contracts, compliance, and claims management. My responsibilities included open enrollment communications focusing on educational campaigns on health, wellness, and retirement benefits. I was heavily involved in benefit planning committees, reasonable accommodations, HIPAA compliance, and the benefit appeals committee. I supervised the employee staff, which was responsible for the payment administration and reconciliation of all the employee benefit plans. I was the project leader for many health care related projects (implementation of Consumer Directed Health Care Plan ("CDHP"), Dependent Audit, Absence Management, etc.).

In 2011, I joined Consumers Energy as a Senior Benefit Consultant in Jackson, Michigan. I took on a project manager role within the Employee Benefits Team. My responsibilities included Annual Enrollment, health care strategy and plan design, union negotiations, Affordable Care Act ("ACA") administration, HIPAA/Compliance, and other health care related projects. In 2017, I became the Manager of Health Care & Retirement with responsibility for health care, retirement, and various other insurance programs for active and retired employees. My insurance responsibilities include health care strategy, premium contributions, plan designs, benefits administration validations, legal compliance, carrier exchanges, eligibility, and rate validations. I oversee management of the retirement benefits plans (Pension Plans, DCCP, and ESP). In 2018, I became responsible for the implementation of our new well-being program, Live Well 365, which focuses on six key elements of total well-being. I continue to manage the Health Care & Retirement team at Consumers Energy. The team is responsible for all aspects of health care and retirement plans administration for our employees and retirees. In 2019, I became the Director of Employee Benefits, which includes the responsibility of my previous role as Manager of Health Care & Retirement, as well as the responsibility of absence management, educational assistance, employee assistance service programs and workers' compensation.

Q. Are you a member of any professional societies or trade associations?

A. I represent the Company as a member of the National Business Group on Health ("NBGH"), an association of over 400, mostly large, employers across the country who provide health coverage to over 55 million individuals. NBGH represents the national voice of large employers dedicated to finding innovative and forward-thinking solutions to the nation's most important health care issues.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide support for the Company's costs related to the electric business portion of retirement, health care, life insurance, LTD plans, and other benefits provided to its employees and retirees. In Part I of my direct testimony, I will address the retirement benefits plans. In Part II of my direct testimony, I will address health care, life insurance, LTD plans, and other benefits, which include absence management, educational assistance, and employee assistance service programs.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-51 (LBC-1)	Summary of Actual and Projected Benefits O&M Expenses for the Years 2018, 2019, 2020 and 2021;
Exhibit A-52 (LBC-2)	CMS Energy – Pension Plans A and B - ASC 715 Pension Expense Estimates; and
Exhibit A-53 (LBC-3)	CMS Energy - ASC 715 OPEB Expense Estimates.

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

A. Yes.

Q. Please describe Exhibit A-51 (LBC-1).

A. Exhibit A-51 (LBC-1) summarizes 2018 through 2021 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 2018 actual expense for each plan. Column (c) provides the actual expense in 2019 for each plan. Column (d) provides the projected expense in 2020 for each plan. Column (e) provides the projected expense in 2021 for each plan.

Q. Please describe Exhibits A-52 (LBC-2) and A-53 (LBC-3)

A. Exhibits A-52 (LBC-2) and A-53 (LBC-3) provide the Aon actuarial projections for Pension and Other Post-Employment Benefits ("OPEB") expenses for 2020 and 2021. Both the Pension and OPEB projections in these exhibits provided by the Aon actuaries are updated from the year-end 2019 measurement of the Pension and OPEB plans and reported in the Company's 2019 Form 10-K filing.

I. RETIREMENT BENEFITS PLANS

Q. Which retirement benefits are you addressing in this section of your direct testimony?

A. I am addressing the Pension Plans, DCCP, and ESP. These expenses are shown on Exhibit A-51 (LBC-1), lines 1 through 3.

Q. How are the Pension Plans, DCCP, and ESP expenses that are common to electric and gas operations allocated to the electric portion of the business?

A. Expenses common to both the electric and gas operations associated with the Pension Plans, DCCP, and ESP are allocated on the basis of the relationship of employee labor dollars charged to electric operations compared to the labor dollars charged in both electric and gas operations. These allocations are made by the Accounting Department. The electric portion of the O&M expense for these plans is shown on Exhibit A-51 (LBC-1).

Pension Plans

Q. Would you please explain your Exhibit A-51 (LBC-1), line 1, which begins with $26,717,000 in 2018?

A. Exhibit A-51 (LBC-1), line 1, shows the actual 2018 and 2019 electric pension expense and the projected electric expenses for 2020 and 2021.

Q. How does the Company determine its expense for the Pension Plans?

A. The pension expense is determined using actuarial analysis that is performed in accordance with Accounting Standards Codification ("ASC") 715. Consumers Energy follows Generally Accepted Accounting Principles ("GAAP") for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodology and assumptions required to properly calculate and account for pension expense which includes evaluation of market conditions at each of the Pension Plan's measurement dates. In addition, the process is rigorously reviewed by the Company's auditor to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of pension expense. 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. The projections were updated by the Company's actuary, Aon. For this electric rate case, the Pension Plans were measured on December 31, 2019 for year-end liability and expense purposes. Projected pension expenses for 2020 and 2021 were also calculated.

Q. What are the components of the annual pension expense under ASC 715?

A. There are four components of the expense: (i) service cost; (ii) interest cost; (iii) expected return on plan assets; and (iv) amortization of gains or losses, prior service cost, 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 his or her 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 positive or negative.

In order to calculate the plan's total pension benefit obligation and annual ASC 715 expense, the actuary uses a number of assumptions including discount rate, mortality table, salary change, expected return on plan assets, and expected future contributions needed to avoid benefit restrictions under the Pension Protection Act. The methods used to set assumptions are generally unchanged annually, while the values of each assumption are determined by the Company each year and reviewed by the Company's auditors and actuary.

Q. Please describe how the discount rate is set each year.

A. The Company relies on its actuary's discount rate setting model. The model uses current high-quality bonds to match the Pension Plan's cash flows using statistical techniques that create a yield curve that determines the effective discount rate for all maturities of pension payments. The model itself does not change annually, but the discount rate will be updated based on the most current market conditions.

Q. Please describe how the expected return on plan assets is set each year.

A. The Company uses future expected capital market assumptions, asset allocation information, and other resources provided by its consultants, which may include survey data and analysis of the Pension Plan's asset allocation. The expected return assumption is based on long-term return expectations and not short-term returns. The Company uses all this information to establish an expected return on plan assets assumption that best estimates its expectation. While this assumption is reviewed for each plan measurement, it may or may not be changed annually depending on the information that is presented.

Q. Please describe the development of the Pension Plans expense shown on Exhibit A-51 (LBC 1), line 1, which begins with $26,717,000 for 2018.

A. Each of the annual pension expense levels shown on Exhibit A-51 (LBC-1), line 1, for the electric utility is based upon Aon's actuarial determination of each plan's total expense for that year in accordance with ASC 715 and includes plan administration fees and Pension Benefit Guarantee Corporation ("PBGC") premiums, aggregated for total pension expense. The Consumers Energy pension expense determined by Aon plus administration fees and PBGC premiums are allocated to the electric and gas portions of the utility using the Accounting Department methodology described earlier. This allocation resulted in the actual electric utility O&M expense for Pension of $26,717,000 in 2018 and $5,546,000 in 2019, and projected expense of $4,341,000 in 2020. For 2021, the electric utility's portion of the projected O&M pension expense is ($4,394,000).

Q. Have there been any significant changes to the Pension Plan structure?

A. Yes. The Company split its Pension Plan into two plans as of January 1, 2018. Generally, all participants who were employees of the Company on August 1, 2017 were included in Pension Plan A. All other participants, including any Cash Balance participants, were assigned to Pension Plan B. No changes to participant benefits occurred as a result of this change. The Company decided to make this change to help manage expenses of the Pension Plans which extended the amortization period for the inactive group and enabled the mitigation of PBGC premium variability.

Q. Did the Company make any cash contributions to the Pension Plans in 2018?

A. Yes, the Company contributed $102,600,000 to Pension Plan A in December 2018.

Q. Did the Company make any cash contributions to the Pension Plans in 2019?

A. No, the Company did not make any contributions to the Pension Plans in 2019.

Q. Did the Company make any cash contributions to the Pension Plans in 2020?

A. Yes, the Company contributed $531 million to Pension Plan A in January of 2020. Of that $531 million, it is important to note that $518 million was the allocated contribution amount for Consumers Energy in total. As a result, the pension contribution directly reduces the overall utility pension expense by $35 million.

Q. What was the rationale for the Company's decision to make a pension contribution in 2020?

A. By making the $531 million pension contribution in early January 2020, the Company was able to fully fund its pension obligation. Fully funding the pension will provide benefit to our customers, employees, and the Company. The fully funded status allows for pension eligible employees to feel a strong commitment from the Company, and it reduces pension expense for customers. This employee commitment is key as it provides for a more engaged and experienced workforce to serve customers well. Also, the fully funded status has several economic advantages as it provides participants with benefit security, avoids risk of restrictions on beneficiaries in the future, and reduces the Company's long-term borrowing cost risk. Furthermore, the fully funded pension contribution eliminates the requirement of certain PBGC premiums, which reduces the Company's pension expense for customers.

Q. Have any changes recently been made to Pension Plans benefits?

A. On September 1, 2015, a change was made to the survivor benefit for a retirement-eligible employee covered by the plan who passes away prior to retirement. In such case, the surviving spouse/beneficiary will automatically receive the employee's full monthly retirement annuity (rather than 50% of the annuity), even if the employee had not completed the paper application process for this benefit prior to passing away.

While this modest 2015 change was made to the Pension Plans, no significant benefit changes have been made to the Pension Plans since September 1, 2005 when the Pension Plans were closed to new hires and the DCCP was implemented for new hires. Increases in pension expense created by the assumption changes are moderated by the closure of the Pension Plans to new hires as of September 1, 2005. In addition, pension liabilities and expenses are moderating overall as many participants are retiring or leaving and commencing their benefits, which reduces the liability and associated expense over time. Liability and expense will continue to diminish (presuming no significant change in the market) until there are no longer any employees or retirees covered by the defined benefit Pension Plans. The changes in the pension expense from 2018, 2019, and 2020 are primarily the result of economic conditions external to the Pension Plans over which the Company has no control.

DCCP

Q. Does the Company provide an alternative qualified benefit plan to the closed Pension Plans for employees hired on and after September 1, 2005?

A. Yes. In order to remain competitive in the area of a benefits package that attracts and retains qualified and talented employees for the benefit of the customer, the Company replaced the Final Average Pay and Cash Balance versions of the qualified defined benefit Pension Plan with the qualified defined contribution DCCP for all existing Cash Balance participants and newly hired employees on and after September 1, 2005.

Q. Are there any employees included in the DCCP that were hired before September 1, 2005?

A. Yes. Those employees who were hired between July 1, 2003 and August 31, 2005, and who were provided coverage under the Cash Balance version of the defined benefit Pension Plan, became participants in the DCCP as of September 1, 2005. As of September 1, 2005, for this specific group of employees, additional pay credits under the Cash Balance version of the defined benefit Pension Plan were discontinued.

Q. Will the Cash Balance version of the defined benefit Pension Plan accept any new employees as participants?

A. No. As with the Final Average Pay defined benefit Pension Plan, the Cash Balance version of the defined benefit Pension Plan now has a finite group of participants that, over time, will diminish until there are no longer any employees or retirees covered under this plan.

Q. Please provide a general description of the DCCP.

A. The DCCP currently provides an employer funded cash contribution of 5% to 7% of the employee's base pay to the ESP. No employee contribution is required to receive the employer contribution. All existing Cash Balance Plan employee participants and employees hired on and after September 1, 2005 participate in the DCCP as part of their retirement benefit package.

Q. Have any recent changes been made to the DCCP?

A. Effective in January 2016, the DCCP provides a 5% to 7% (previously 6%) employer funded cash contribution based upon the employee's service time with the Company. New hires receive a 5% contribution, which increases to 6% when they have six years of service with the Company. Employees receiving a 6% contribution before January 1, 2016 continue to receive their 6% employer contribution. When employees reach 12 years of service, they receive a 7% employer contribution. This service-based contribution approach for the DCCP serves as a talent retention mechanism and helps contain the cost of the DCCP for the benefit of the customer as all new hires starting in 2016 began receiving a 5% (previously 6% for new hires) employer contribution.

Q. Would you please explain your Exhibit A-51 (LBC-1), line 2, which begins with $7,628,000 in 2018?

A. Exhibit A-51 (LBC-1), line 2, represents the electric operations O&M expense related to the DCCP. The actual electric operations expense for this plan in 2018 was $7,628,000 as shown in column (b). Column (c) shows the actual 2019 electric DCCP expense of $8,567,000. Column (d) shows the projected electric DCCP expense of $9,741,000 for 2020. Column (f) shows the projected electric DCCP expense of $11,202,000 for 2021.

Q. As a result of the revised eligibility requirements for participation in the Final Average Pay defined benefit Pension Plan or the Cash Balance version of the defined benefit Pension Plan, is it correct to say that all new hire employees starting with September 1, 2005 and after will receive their retirement benefits through plans that are referred to as defined contribution type plans?

A. Yes. The primary plans that will provide monetary benefits to this group of employees upon retirement are the DCCP and the ESP.

ESP

Q. Please explain briefly how the ESP works.

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. The Company currently matches 100% of the employee's first 3% in contributions and 50% of the employee's next 2% in contributions to the ESP. Employee contributions beyond 5% are not matched by the Company. Consumers Energy's expense includes the Company 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 2016, the Company match changed to 100% of employee contributions of up to 3% of the employee's salary, and then 50% of employee contributions of up to the next 2% of the employee's salary (previously 60% of employee contributions up to 6% were matched). Employee contributions beyond 5% 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.

Q. Would you please explain your Exhibit A-51 (LBC-1), line 3, which begins with $7,982,000 in 2018?

A. Exhibit A-51 (LBC-1), line 3, represents the Company's electric operations expense related to the ESP. In 2018, the actual electric utility O&M expense for the ESP was $7,982,000. For 2019, the actual electric utility O&M expense for the ESP is $8,273,000. For 2020, the electric utility O&M expense projected for the ESP is $8,672,000. For 2021, the electric utility O&M expense projected for the ESP is $9,189,000.

Q. Is the ESP employer matching program important to attracting and retaining employees?

A. Yes.

Q. Please explain why the ESP employer matching program is important to attract and retain employees.

A. The ESP with a match is commonly available from Michigan employers as well as from other utility company employers that Consumers Energy competes with for employee talent. It is necessary to continue providing this highly visible, competitive benefit to employees of Consumers Energy to continue attracting and retaining competent employees needed by the Company, particularly in light of the large number of retirement eligible employees at the Company. Attracting qualified employees and retaining this talent maximizes the efficiency of the Company's labor force and reduces costly turnover. Retaining trained, experienced, and motivated employees works very much to the customers' benefit.

Q. Is the ESP employer match "discretionary"?

A. It is not discretionary for union employees. A provision in the Working Agreement ratified in 2005 with Operating Maintenance & Construction ("OM&C") and Virtual Call Center ("VCC") union employees assured these employees that the match would not be suspended during their five-year contract. This provision was renewed in the 2010 contracts as part of the final union agreements for these union groups, and it is also part of the new Steelworker's union contract effective January 1, 2011. This provision was not changed in the most recent five-year contracts negotiated in 2015. This has been an important issue to the union during the last several labor negotiations, all of which were finally resolved through arms-length bargaining.

With respect to nonunion employees, there is not a similar contractual prohibition against suspension. However, the ESP employer match is part of an overall competitive benefit package and employees depend upon its continuation so that they can accumulate savings for retirement. The Company's competitors continue to offer a savings plan match, and the Company plans to continue offering the match to compete for new talent and retain current talent for the benefit of the customer. As noted above, it is a benefit that helps the Company attract and retain qualified and talented employees. From a practical standpoint, the Company views the employer match as non-discretionary.

II. <u>HEALTH CARE, LIFE INSURANCE, LTD PLANS, AND OTHER BENEFITS</u>

Q. Which health care and insurance benefits are you addressing?

A. I am addressing active employee health care (including HSAs and HCFSAs), life insurance, and LTD plans; retiree health care and life insurance plans; and other benefits, which includes absence management, educational assistance, and employee assistance service programs. These expenses are shown on Exhibit A-51 (LBC-1), lines 4 through 6.

Q. Are the expenses for active employee health care (including HSAs and HCFSAs), life insurance, and LTD benefits determined in the same way as expenses for retiree health care and life insurance benefits?

A. No. The expenses for active employees are based upon the actual costs for these benefits that are expected to be incurred. The expenses for retirees are determined using actuarial analysis, which is performed by the Company's actuary, in accordance with ASC 715, formerly known as Financial Accounting Standards ("FAS") 106.

Q. How were the portions of active employee and retiree health care (including HSAs and HCFSAs), life insurance, LTD, and other benefits costs allocated to electric O&M expense determined?

A. The portion of the Company's total program expenses attributable to the electric utility was allocated based upon an annual study by the Accounting Department of the relationship of the number of employees in the electric utility to the total number of employees in both the electric and gas utility. The amount allocated to the electric utility is allocated between O&M expense and capital expense based upon the Accounting Department's formula.

Q. Please describe the development of the active health care (including HSAs and HCFSAs), life insurance, and LTD expense levels that are shown on Exhibit A-51 (LBC-1), line 4, which begins with $24,194,000 in 2018.

A. Exhibit A-51 (LBC-1), line 4, contains electric operations O&M expenses for the Company-subsidized benefit plans for active employees' health care (including HSAs and HCFSAs), life insurance, and LTD. The primary component of this expense is health care.

Life insurance and LTD expenses make up a much smaller portion of the expense. In 2018, the Company incurred an actual combined expense of $24,194,000 for health care, life insurance and LTD for electric operations. The Company's actual expense for these benefits is $25,353,000 in 2019. The projected electric operation expense for these benefits in 2020 is $25,948,000. For 2021, the projected electric operations expense is $27,473,000.

Q. What factors did you consider in projecting the Company's 2020 and 2021 health care, life insurance, LTD, and other benefits expenses?

A. In projecting expected 2020 and 2021 health care expenses, a number of factors were considered. Primary factors included review of 2018 through 2020 national health trends/costs survey information, the Company's medical and prescription drug carrier's health cost and claims experience expectations, the continuing rapid rise in availability and price of specialty prescription drugs, the ages of the Company's employee workforce and its retirees, the continuation and improvement of the Company's well-being initiative for employees and retirees, changes to the 2016 through 2020 OM&C/VCC/Steelworkers union employee health care benefit contract provisions, changes to the 2020 employee health care plans, the current employee headcount, and the continuing cost increase impacts of national health care reform. All these factors are included in the 2019 and 2020 rate studies (projecting 2020 & 2021 expenses) completed by the Company and Willis Towers Watson ("WTW") actuarial consulting.

Q. Please explain how these factors were used to determine the Company's expected health care costs in 2020 and 2021.

A. To help understand projected health care trends and costs in 2020 and 2021, the Company and WTW reviewed expected health care trends and costs survey information from several large consulting firms. Recent 2019 health care trend and cost surveys included in the review were Aon and WTW. For 2020, medical health care trend (per capita claims cost) is expected to increase 6% on just medical expenses. The leading medical trend contributor is prescription drugs, which was expected to trend 10% higher in 2019. A review of these projected trends in medical and prescription expenses serves as a basis of what to expect in future medical expense increases.

The Company and WTW also reviewed the Company's actual health care claims experience for employees and retirees in its health plans - Blue Cross/Blue Shield of Michigan, Express Scripts, Priority Health, and Blue Care Network. The Company's health plans indicate that the Company's workforce is older than the average in their plans, and, as a result, has a higher expected utilization rate of services that is associated with an older covered population. Of the Company's current workforce on December 31, 2018, 48% of employees are over the age of 45; 34% are over the age of 50; and 19% are over the age of 55. The Company understands the older age of its workforce is expected to lead to higher health care expense (primarily due to utilization of services). Most of these discussions with the Company's health plans suggest health care expenses are expected to increase 5% to 8% for 2020 and 2021. Historical claims experience data for Consumers Energy participants was also gathered from these health care companies to be used in the 2020 and 2021 health care expense impact studies completed with WTW to determine the Company's projected expense increases in 2020 and 2021.

To project future health care expenses, the Company and WTW also considered all the plan changes and programs the Company has already implemented, which are summarized below and detailed later in this testimony. These changes include sharing expected health care expense increases with employees through plan design changes, including increased deductibles, copayments, and out-of-pocket maximums; increasing employee premium contributions for coverage; adding telehealth benefits to medical plans to lower expense; educating employees regarding the prudent and informed use of health care benefits; promoting use of preventive benefit services; promoting well-being through Live Well 365, which is integrated into all medical plan designs, that encourages and rewards plan participants for taking steps toward healthier lifestyles; securing favorable pricing on prescription drugs obtained through a large employer prescription drug collaborative; negotiating lower administrative fees with health plans and promoting enrollment into the CDHP, a high deductible health plan which currently provides a Company contribution to the participant's HSA.

The Company and WTW also considered the specific changes to the union employees' health care plan benefits as negotiated in its 2016 through 2020 contracts, as well as changes made to the employees' health care benefit plans in 2020 described in detail later in this testimony. While there are very tangible savings in future health expenses to the Company and its customers as a result of these changes to employee health care benefit plans, the Company believes a portion of these savings will be offset by increased health expenses incurred under national health care reform requirements (like Patient Centered Outcomes Research Institute fees, employer mandate shared responsibility administrative/reporting requirements, and potential penalties), as well as increased prescription expenses due to the availability of new and expensive specialty prescription drugs in the market. In addition, while the Company has taken numerous steps to control the rising expense of health care, many of these changes are one-time events that lower a plan's expense in that year to establish a new baseline moving forward, but future health care expenses then continue to increase from the new baseline expense.

Based upon the analysis of all of this information, including health plan demographics and current enrollments, the Company, and its independent employee health care actuarial consultant, WTW, projected in its rate studies that for 2020, the expected health care expense increase for the Company will be 4.5% after all plan design and premium contribution changes are considered for 2020. Although the 2021 plan changes are not yet known, the Company will continue to seek to contain expense, and the Company's health care expense is projected to increase 6.1% in 2021 over 2020 expense. The Company used these WTW actuarially based studies to set its projected active health care expenses for 2020 and 2021. As a result, the Company projects its expected health care expense will increase 4.5% for 2020 (the projected 2020 increase from the 2019 WTW study) and 6.1% in 2021.

Q. What are some of the reasons that health care costs are increasing at a level higher than general inflation?

A. There are a number of factors causing a much higher rate of health care inflation than is reflected in the general Consumer Price Indexes ("CPIs"). Health care costs are expected to continue rising during the next several years due to an aging population living longer, additional utilization of services, price increases for services, new medical technology, cost shifts from government plans, mandated benefits coverage, rising provider malpractice premiums, new taxes on health claims, and rapidly escalating prescription drug prices including high prices for new, expensive specialty drugs. In addition, recently enacted national health care reform will increase Company health care costs as a result of eligibility expansions (e.g., adult children to age 26), mandated benefits, removal of annual dollar limits, additional taxes, fees and penalties, new compliance/reporting requirements, and more government shifting of costs through Medicare and Medicaid expansion. These factors are all outside the control of Consumers Energy. Even with all the employee and retiree health plan design and premium contribution changes made annually by the Company over a number of years, including the move to Live Well 365 program incentives, health care costs for the Company are still expected to continue increasing annually at a rate two to three times that of general CPI inflation. The assumption that health care costs will only increase at the general rate of inflation has not been the actual experience for many years and is not expected in the foreseeable future.

Q. Are large increases in health care costs being experienced both locally and nationally?

A. Yes. While increases in health costs have moderated somewhat, both local and national health care costs continue to increase at rates much greater than general CPI inflation.

Q. Are the significant increases in health care costs limited to active employees?

A. No. Health care costs are also increasing at a rate higher than the general CPI inflation for retirees for the same reasons cited earlier. In fact, retiree expenses are generally increasing at higher rates because of retirees' older ages and the resulting increases in utilization, particularly in the use of prescription drugs, including higher-priced specialty prescription drugs. The projected increases for active employee health care, like projected increases for retiree health care, are substantial, reasonably expected to occur, and largely beyond the control of the Company.

Q. Please describe the development of the expense levels for active employee life insurance and LTD costs included in Exhibit A-51 (LBC-1), line 4.

A. For 2020 and 2021, the Company used a 3.5% annual increase in cost for both years. This means 2020 life insurance and LTD expense is expected to be 3.5% higher than 2019 and 2021 expense will be 3.5% higher than 2020. These expense estimates are reasonable as both life insurance and LTD premium costs are based on wage and salary levels and changes to this coverage throughout the year. The 3.5% annual increase reasonably represents the normal, expected merit increase in salaries/wages, increases due to salary adjustments made for job changes and promotions throughout the year, any upward movement in Company-paid life insurance coverage in each annual enrollment period, and increases in premium rates due to plan experience.

Q. What has the Company done to control the increase in active employee and retiree health care, life insurance, and LTD expenses?

A. The Company has aggressively managed these benefit costs for more than a decade. Significant changes have been made to all health care, life insurance, and LTD plans since the introduction of the Benefit by Choice program first implemented in 2002, which offered employees and retirees different levels of health, life, and LTD coverage. A summary of various changes made to manage the cost of the Company's health care plans offered to employees and retirees from 2002 through 2020 follows:

- Reduced the number of healthcare plan offerings by eliminating two health maintenance organization ("HMO") plans;
- Joined prescription drug collaborative to improve efficiencies on pricing, customer service and access to affordable prescription drug coverage;
- Streamline all benefit plans to be 80% coverage levels;

- Offered telemedicine option for those seeking treatment for non-emergent conditions;
- Increased employee/retiree premium contribution levels annually;
- Implemented Preferred Provider Organization ("PPO") plans, providing discounted networks to all participants;
- Reduced PPO plan benefit coverage levels from 90%, 80%, and 70% to 85% and 70%;
- Reduced HMO plan benefit coverage levels from 100% to 90%;
- Increased employee/retiree PPO and HMO plan design cost sharing provisions including: medical/dental deductibles, out-of-pocket limits, office copays, urgent care copays, and emergency room copays on several occasions;
- Switched to Maintenance of Benefits ("MOB") coordination;
- Required covered spouse working full-time to have own employer coverage primary;
- Negotiated administrative fees and insured plan premium rates annually and bid the health plan market to improve pricing;
- Increased employee/retiree prescription drug benefit cost sharing through incentive four-tier plan designs, higher prescription drug copays and coinsurance, and use of an exclusive network for specialty drugs;
- Implemented prescription drug management programs including: full-menu, dynamic-based coverage management programs, mandatory use of mail order, safety/efficiency provisions, and regular market bids for pricing through an employer collaborative;
- Implemented health and disease management programs and added case management;
- Implemented a Company-defined dollar contribution plan management approach;
- Eliminated duplicative, higher cost health plan offerings on several occasions;
- Introduced informed consumerism, cost information, and credible health resources;
- Used enhanced technology for more timely determination of plan eligibility and coverage;

- Implemented access-only retiree health care benefits for new hires (no Company subsidy);
- Implemented preventive benefits with no cost sharing, included the mandated changes required under the ACA;
- Implemented and promoted enrollment in a CDHP with an HSA;
- Increased premiums and out-of-pocket limits;
- In 2018, implemented new total well-being program called Live Well 365. This program allows employee/preMedicare retirees to be engaged in their total well-being through a variety of well-being activities including, but not limited to, preventive exam, well-being assessment, physical challenges, and a variety of other activities available to increase year-round engagement. For those participants who complete level 1 of the Live Well 365 program, they remain in a higher benefit coverage level or receive an additional Company HSA contribution. Employees/preMedicare retirees that do not participate in Live Well 365 are moved to a higher out-of-pocket cost benefit coverage level or do not receive the second Company HSA contribution;
- Separated employee/retiree medical and dental plans to minimize reporting and compliance costs required by the ACA;
- Changed insured HMO plans to self-insured HMO plans;
- Implemented an ongoing medical/dental/vision plan dependent audit process to ensure only eligible employees, retirees and their dependents are covered by these plans; and
- Secured improved prescription drug pricing and plan consulting services as part of membership in a large prescription drug employer prescription drug purchasing collaborative.

Q. What changes were made to the 2017 health care plans?

A. In 2017, the same health care benefit changes were made for all union and nonunion employees, as well as all preMedicare retirees. The Healthy Living health plan designs were changed to comply with new Equal Employment Opportunity Commission requirements. This required only the employee and preMedicare retiree, not covered spouses, to complete their Healthy Living steps under the wellness plan design. Those employees and preMedicare retirees that completed their two Healthy Living steps in 2017 had less cost sharing in their health plans or received a second Company contribution to their Health Savings Account in 2017.

In addition, the ACA expanded nondiscrimination definitions to include gender identity. As a result, the Company added coverage for gender transition benefits to all its health plans.

Finally, all health plan premium contributions for employees and preMedicare retirees were increased to share in expected increased costs in 2017.

Q. What changes were made to the 2018 health care plans?

A. In 2018, deductibles and out-of-pocket limits increased in the majority of plans for all salaried and union employees as well as early retirees. Several prescription drug coverage management programs were added to help participants better manage various chronic and expensive medical conditions. The CDHP increased out-of-pocket limits, as well as reduced Company HSA contributions. The prescription drug plans increased specialty drug copays. A refreshed well-being approach was introduced with the new Live Well 365 to encourage and incent plan participants to improve their health and well-being year-round. Premium contributions were increased across all health plans to help manage the expected expense increases for the Company.

Q. What changes were made to the 2019 health care plans?

A. In 2019, deductibles and out-of-pocket limits increased for the HMO plans. The Company introduced a CDHP plan with no HSA seed from the Company. The employee share of health care plans also increased.

The active employee health care expense for the Company, after consideration of all these changes, was expected to increase 3.9% in 2019, as documented in the WTW rate study.

Q. What changes were made to the 2020 health care plans?

A. In 2020, we discontinued offering our HMO plans for our active employees and preMedicare retirees. This change is due to declining enrollment and higher medical and prescription costs in the HMO plans. Active employees have the option to choose from three other high-quality PPO plans for 2020 coverage. The PPO plans offer an expanded network of providers both in and out-of-network. Active employees who elected our CDHP will have the ability for saving options for current and future health care expenses through a health savings account. The employee share of health care premium contribution also increased for most participants.

The active employee health care expense for the Company, after consideration of all these changes, is expected to increase 4.5% in 2020 and 6.1% in 2021, as documented in the WTW rate study.

Q. Would you please explain your Exhibit A-51 (LBC-1), line 5, for retiree health care and life insurance, which begins with ($56,384,000) in 2018?

A. Exhibit A-51 (LBC-1), line 5, reflects the actual 2018 and 2019 O&M expenses as well as projected expenses for 2020 and 2021 electric utility retiree health care and life insurance 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 for retiree health care and life insurance and an actuarial services expense.

Q. How does the Company determine its ASC 715 expense for retiree health care and life insurance?

A. The expense is determined using actuarial analysis that is performed in accordance with ASC 715. Consumers Energy follows GAAP for its financial statements. Under the provisions of GAAP, ASC 715 describes the methodologies and assumptions required to properly calculate and account for retiree health care and life insurance expense which includes evaluation of market conditions at each of the plan's measurement dates. The calculations required by the accounting standards are performed at least annually by the plan's actuary, Aon, using information specific to the Company's OPEB plan. In addition, the process is rigorously reviewed by the Company's auditor to ensure compliance with GAAP and ASC 715.

ASC 715 requires an annual determination of retiree health care and life insurance expense (OPEB expense or FAS 106 expense). The expense is determined based on actuarially-reviewed employee census data, the plan provisions, plan assets, and certain other actuarial assumptions. Year-end disclosure information is also produced, based on these accounting standards, to provide a reconciliation of plan assets and liabilities at the end of the Company's fiscal year. For this electric rate case, OPEB was measured on December 31, 2019. The OPEB projected expense in this case for 2020 and 2021 is based upon the December 31, 2019 measurement of the OPEB plan.

Q. What are the components of the annual ASC 715 retiree health care and life insurance expense?

A. There are four components of the annual ASC 715 expense: (i) service cost; (ii) interest cost; (iii) expected earnings on plan assets; and (iv) amortization of gains and losses, prior service costs, and any transitional amounts. Service cost represents one year's expected benefits earned by active covered employees. Interest cost represents interest on the plan's benefit obligation (its liabilities) due to the passage of time. There is also an assumption made for the expected rate of return on plan assets. This rate of return assumption is intended to be a long-term assumption based upon the best estimate of long-term expected investment earnings of the plan assets. The last component represents amortization of various plan experiences that were not anticipated by the actuarial assumptions.

In order to calculate the plan's total benefit obligation and annual ASC 715 expense, the actuary uses a number of assumptions including health care inflation trend rates, mortality table, the rate of employee retirements from the Company, the actual retiree health care and life insurance claims of the Company, a discount rate, and the expected contributions to the plan. The methods used to set assumptions are generally consistent, while the values of each assumption are determined by the Company each year and reviewed by the Company's auditors and actuary. The method to set the discount rate and expected return on plan assets is the same as the method used for the pension plans, as discussed above.

Q. Are actuarial and administrative expenses included in Exhibit A-51 (LBC-1), line 5?

A. Yes. An annual expense for the actuarial and administrative services provided for the retiree health care and life insurance plans is included in Exhibit A-51 (LBC-1), line 5.

Q. What changes were made to retiree health care coverage from 2011 to 2020?

A. The same plan changes described previously for active union and nonunion employees from 2011 to 2020 were made to all the preMedicare retiree plans. These changes included the Live Well 365 program requirements, increased plan deductibles, copays and out-of-pocket limits, various plan eliminations, four-tier incentive prescription drug coinsurance plans, self-insured HMO plans, a CDHP/HSA plan option, increased premium contribution requirements, additional prescription drug coverage management programs, and the implementation of MOB coordination. In addition, as described earlier in the ESP section above, all new union hires since September 1, 2010 (nonunion hires since January 1, 2007) may become eligible for an access-only retiree health care plan at retirement which requires 100% retiree premium contribution for coverage at retirement and provides for no Company contribution or subsidy and results in no Company ASC 715 liability or expense.

The Medicare retiree plan was also changed throughout this 2011 to 2020 period with similar changes including increased deductibles and out-of-pocket limits, MOB coordination, a new four-tier incentive prescription drug copay plan, and increased premium contribution requirements. Specifically, in 2018, Medicare retirees have increased prescription drug copays and the addition of specialty drug copay in their plan. In addition, premium contributions for most Medicare retirees increased to 15% of the plan's cost.

Q. Were additional significant changes to retiree medical coverage announced during 2013?

A. Yes. The Company made a change to the financing arrangement for providing its prescription drug coverage to Medicare retirees effective January 1, 2015. The Company moved away from the Retiree Drug Subsidy approach and implemented an Employer Group Waiver Plan ("EGWP") with wrap coverage. The EGWP with wrap coverage allows the prescription drug benefit plan to deliver the same or very similar prescription drug benefit coverage and cost sharing to the Company's Medicare retiree supplemental health plan participants. Due to a couple of national health care reform changes involving increased prescription drug subsidies and manufacturer discounts under an EGWP financing approach, the Company's cost for providing Medicare retiree's prescription drug coverage decreases significantly as drug manufacturers' discounts and Medicare subsidy payments will cover a portion of the Company's prescription drug benefit costs.

In addition, the Company announced the implementation of an increasing schedule of premium contributions for its Medicare retirees covered under the Company's Medicare Supplemental Plan beginning January 1, 2016. The Company indicated it would begin to phase in a schedule of premium contributions for many of its current Medicare retirees and all of its future Medicare retirees eligible for subsidized retiree health care coverage. Medicare retirees on lower fixed incomes, who have been retired for a longer period of time, will not pay premium contributions under this provision. For younger Medicare Supplemental Plan retirees, premium contributions started at 5% of the plan's cost in 2016 and gradually move to 10% in 2018, while younger Medicare retirees will pay 15% of plan costs by 2020. Premium contributions percentage amounts are dependent upon the retiree's age on December 31, 2013.

Q. Were additional significant changes to retiree medical coverage announced during 2017?

A. Yes. The Company expects that most of its current Medicare retirees and all future Medicare retirees will begin to choose their Medicare retiree health care benefit plans from the individual Medicare Marketplace beginning January 1, 2019 rather than be covered by the Company's one current supplemental Medicare health plan. These retirees will receive assistance in their plan elections and be provided advocacy services by a private Medicare Marketplace company selected by the Company. Medicare retirees eligible to receive subsidized retiree coverage from the Company will instead receive a Company-funded Health Reimbursement Arrangement to reimburse them for their premium and out-of-pocket costs for the plan(s) elected in the individual Medicare Marketplace. This change to the individual Medicare Marketplace offers the Company's Medicare retirees a much greater choice of plans and flexibility to select coverage that best meets the Medicare retiree's individual needs. Also, due to the cost efficiency of the individual Medicare Marketplace, it will provide more affordable coverage for Medicare retirees now and well into the future.

Q. Were additional significant changes to retiree medical coverage announced during 2018?

A. Yes. The Company announced an improved survivor benefit for Medicare retirees. All eligible surviving spouses will continue subsidized healthcare for their remaining lifetime.

Q. What changes were made to the 2019 retiree health care plans?

A. The preMedicare retirees have the same health care plan options as the active union and nonunion employees. The Company partnered with an individual Medicare marketplace provider for specific Medicare eligible retirees to select their own coverage. The Company provided a Health Reimbursement Account ("HRA") to retirees based on years of service and hire date. The retirees worked with a benefits consultant to select the best quality and affordable health care coverage.

Q. What changes will be made to the 2020 retiree health care plans?

A. The preMedicare retirees have the same health care plan options as the active union and nonunion employees. The preMedicare retirees will no longer have the option to select the HMO health care plans. The Medicare eligible retirees who receive a company subsidized HRA, will receive a 2% increase into their HRA. These retirees select their retiree health care coverage through an individual Medicare marketplace. The private Medicare marketplace specializes to assist retirees to select the best quality healthcare plan options at the most affordable price. The HRA subsidy amount is allotted based on years of service and hire date.

Q. Do the calculations for the retiree health care and life insurance expense follow the prescribed methodology of ASC 715?

A. Yes. The amounts are projected based on ASC 715 using information specific to the Company's retiree health care and life insurance plans. For this electric rate case, the OPEB plan was measured on December 31, 2019 by the Company's actuary Aon. The OPEB projected expenses in this case for 2020 and 2021 are based upon the December 31, 2019 measurement of the OPEB plan.

Q. Has the Company applied the new Financial Accounting Standards Board ("FASB") Presentation of Pension/OPEB Costs Standard in this case for OPEB?

A. Yes, the Company early adopted this new FASB Presentation of Pension/OPEB Costs Standard as of January 1, 2017 and has applied the new Standard in this case for both Pension and OPEB.

Q. Please describe the development of the retiree health care and life insurance expense levels that are shown on Exhibit A-51 (LBC-1), line 5, which begins with ($56,384,000) in 2018.

A. Each of the O&M retiree health care and life insurance expense levels shown on Exhibit A-51, line 5 for the electric utility is based upon Aon's actuarial determination of the plan's expense for that period in accordance with ASC 715 plus the cost for actuarial and administrative services related to these plans. Due to the retiree medical plan changes described earlier, the actual 2018 O&M retiree health care and life insurance expense for the electric utility was ($56,384,000). In 2019, the actual electric O&M expense for these benefits was ($40,032,000). The projected electric O&M retiree health care and life insurance expense is ($53,066,000) in 2020. For 2021, the projected electric O&M retiree health care and life insurance expense is ($53,639,000).

To determine the projected 2020 and 2021 ASC 715 expense for Consumers Energy retiree health care and life insurance, the December 31, 2019 actuarial measurement of the OPEB plan was used.

Q. Why is the retiree health care and life insurance expense so low?

A. Improved 2013 through 2020 prescription drug pricing, the 2013 announcement by the Company of EGWP and Medicare retiree premiums, and the announced change to individual Medicare Marketplace coverage for most Medicare retirees in 2019 are the primary drivers for the significantly reduced OPEB expense for retiree health care and life insurance. These retiree coverage changes are significant and have turned the expense from positive to negative, greatly benefiting customers with reduced costs going forward.

Q. Would you please explain your Exhibit A-51 (LBC-1), line 6, for Other Benefits, which begins with $825,000 in 2018?

A. Exhibit A-51 (LBC-1), line 6, reflects the actual 2018 and 2019 expenses and projected expenses for 2020 and 2021 electric utility benefits for absence management, educational assistance, and employee assistance service programs (the employee assistance service program, which is a new program discussed below, was not included in 2018 actuals).

Q. Please explain why the absence management program is important to attract and retain employees.

A. A 2018 WTW benchmarking study indicates that 91.7% of 84 energy companies nationwide provide a paid sick leave to their employees. Paid sick leave is needed to attract and retain quality employees. In 2014, the Company retained Reed Group, an external consultant to manage the Company's absence process. Since the relationship's inception, Reed Group has been able to improve the absence rate and provide tracking information to the Company. The Company's absence rate decreased from 3.88% in 2014 to 3.63% in 2017. The reduction in absences results in lower labor costs and higher productivity. The benefit of the absence management program is clinical nurse case management. This allows for the resources for our employees as they navigate through their illness. The clinical nurse case management provides medical knowledge and assistance to our employees. Additionally, this streamlined approach ensures a procedure for all employees who need a leave of absence for any purpose.

Q. Please explain why the educational assistance program is important to attract and retain employees.

A. Educational assistance programs are very much available from Michigan employers, as well as from other utility company employers that Consumers Energy competes with for employee talent. A 2018 WTW benchmarking study indicates that 98.8% of 84 energy companies nationwide provide full (16.7%) or partial (82.1%) tuition reimbursement to their employees. The Company offers partial tuition reimbursement to all employees. It is necessary to continue providing this highly visible, competitive benefit to employees of Consumers Energy in order to continue attracting and retaining competent employees needed by the Company, particularly in light of the large number of retirement eligible employees at the Company. Attracting qualified employees and retaining this talent maximizes the efficiency of the Company's labor force and reduces costly turnover. Retaining trained, experienced, and motivated employees works very much to the customers' benefit. Additionally, educational assistance provides the opportunity for our employees to continue their education which further improves their skills to serve the customers of the Company.

Q. Please explain why the employee assistance service program is important to attract and retain employees.

A. The Company offers our employees, retirees, and dependents access to an assistance program which provides support to help resolve or manage problems that interfere with the ability to perform at work or in life. The employee assistance service program provides a variety of on-line tools, face-to-face interactions, and telephone support. The program is designed to aid with any type of need, distraction, concern, or crisis. The employee assistance service program provides legal support, financial information, work-life solutions, online services, and confidential counseling. The goal of the program is to improve the overall total well-being for all of the Company's employees and retirees.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697

DIRECT TESTIMONY

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

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 Director of Executive and Incentive Compensation for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your educational background?

A. I graduated from Central Michigan University in 1999 with a Bachelor of Science Degree in Business Administration with a major in Accounting. In addition, I am designated as a Certified Compensation Professional and Certified Executive Compensation Professional by WorldatWork and a Certified Public Accountant by the Michigan Association of Certified Public Accountants. WorldatWork is an international professional organization focused on human resources issues, including compensation, benefits, work life, and integrated total rewards to attract, motivate, and retain a talented workforce.

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

A. In February 2002, I joined Consumers Energy as a Financial Reporting and Technical Accounting Analyst. My duties included accounting and reporting of equity-based compensation, technical accounting standard research, and preparation of quarterly and annual Securities and Exchange Commission ("SEC") filings. After eight years of progressing responsibilities in this role, I transferred to the position of Principal Human Resources Consultant. In 2013, I was promoted to the position of Director of Compensation. In this role I had the responsibility for administering Consumers Energy's compensation function and partnering with Labor Relations on union compensation matters. This included developing compensation programs designed to attract and retain a qualified workforce for the Company. My duties included gathering of comparable wage and salary data in order to determine how Consumers Energy's pay level compares to the labor market and developing compensation programs that are competitive and deliver pay to employees that is fair and equitable and that motivates employees to perform at their full potential.

My responsibilities also consisted of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers.

In May 2018, I took on the role of Director of Executive and Incentive Compensation. My responsibilities consist of assisting with preparation of materials for the Compensation Committees of the Consumers Energy and CMS Energy Boards of Directors, including the Compensation Discussion & Analysis section of the annual proxy statement for the named executive officers. My responsibilities also include administering the incentive plans for CMS Energy, including Consumers Energy.

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

A. Yes, I have testified in Case Nos. U-17087, U-17197, U-17643, U-17735, U-17882, U-17990, U-18124, U-18322, U-18424, U-20134, U-20322, and U-20650.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide support for Consumers Energy's request for rate recovery for costs of its annual Employee Incentive Compensation Plan ("EICP") at target levels. The EICP is a form of short-term incentive. Short-term incentive pay is designed to focus and reward performance over periods of approximately one year or less.

First, I will discuss Consumers Energy's overall compensation philosophy. In this section of my direct testimony, I will discuss the importance of paying employees a competitive level of compensation and the reasonableness of the overall compensation levels that the Company is requesting in this case. In addition, I will discuss: (i) the fact that EICP compensation is part of an employee's overall market-based compensation and not in addition to it, and (ii) why Consumers Energy has included EICP at target levels as part of overall market-based compensation.

Second, I will discuss the EICP incentives and provide support for the Company's request for rate recovery in this case related to Consumers Energy's non-officer and officer EICP. In my direct testimony, I will discuss the design of the EICP.

Third, I will discuss customer-related benefits that result from use of the incentive plans and how customers are best served when Consumers Energy can attract, retain, and motivate a talented workforce with compensation packages that are competitive and fair. Elimination of the EICP would result in Consumers Energy's employee compensation being below market and would hinder the Company's ability to attract and retain a qualified workforce that best serves customers.

Q. Please summarize your conclusions.

A. My conclusions include the following: (i) use of incentive compensation by utility companies is an accepted, common, and reasonable practice; (ii) Consumers Energy's decision to make a portion of compensation at-risk and subject to incentives is reasonable; (iii) the amount of overall compensation included by Consumers Energy in this case is reasonable and is reasonably necessary to attracting and retaining a talented workforce; (iv) incentive compensation is part of the reasonable level of market-based compensation and not in addition to it; (v) recovering costs of Consumers Energy's EICP employee incentive plans will not result in excess rates; (vi) Consumers Energy's EICP performance goals and thresholds provide customer-related benefits; and (vii) the EICP goals provide customer-related benefits at no incremental cost to customers above those included in market-based compensation.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

I. OVERVIEW

II. EMPLOYEE COMPENSATION PHILOSOPHY

III. INCENTIVE COMPENSATION PLANS

A. Description of Incentive Plans

B. Assessment of Customer Benefits of the Incentive Compensation Plans

IV. CONCLUSION

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-55 (AMC-1)	EICP Performance Measures;
Exhibit A-56 (AMC-2)	Target Pay Level Market Analysis; and
Exhibit A-57 (AMC-3)	Summary of Actual and Projected Annual Incentive O&M Expenses.

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

A. Yes.

I. OVERVIEW

Q. What is the Company's compensation philosophy for non-officer employees?

A. Consumers Energy's compensation philosophy for its non-officer non-union employees is to provide market-based compensation tied to performance. A competitive compensation policy benefits customers by attracting and retaining employees with the necessary skills and experience to deliver world class customer service and minimize the risks and costs of employee turnover. Incentive pay is a component of providing market-based compensation.

Q. What is the Company's compensation philosophy for officer employees?

A. Consumers Energy's compensation philosophy for its officers is centered around four principles:

1. Align with Increasing Shareholder and Customer Value;
2. Enable Us 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 on this philosophy.

Q. How does Consumers Energy structure non-officer compensation for its salaried employees?

A. Consumers Energy first determines what a competitive level of pay is for salaried non-officer employees. It does so using various market surveys. Consumers Energy then structures the compensation by allocating this market-based wage between base salary and incentive compensation. The incentive compensation is part of the overall market-based competitive level. It is not in addition to it. Total compensation is targeted at approximately the market median (50^{th} percentile).

Q. How does Consumers Energy structure officer compensation?

A. Officer compensation levels are determined by the Compensation Committees of the Boards of Directors of Consumers Energy and CMS Energy. The Company creates a compensation package for officers that deliver base salary, annual incentive compensation, and long-term incentive compensation targeted at the median or 50^{th} percentile of the competitive market. In determining individual officer compensation levels, the Compensation Committees are advised by an independent third-party consultant and take into consideration market research, experience levels, and individual contributions.

Q. Is Consumers Energy requesting recovery of long-term incentive pay in this rate case proceeding?

A. No. The Company in this case is not seeking recovery for the costs of long-term incentive compensation (sometimes referred to as restricted stock plans) in its rate recovery request.

Q. In this proceeding, is the Company requesting recovery in rates of all Operating and Maintenance ("O&M") electric expenses related to short-term incentive compensation plans?

A. No. While the Company believes that both officer and non-officer short-term incentive compensation expenses are reasonable, the Company in this case is excluding the costs of short-term incentive compensation for the proxy officers as identified by the most recent SEC proxy filing from its rate recovery request.

Q. Why is the Company requesting recovery in rates of short-term incentive compensation expenses?

A. Consumers Energy uses market data to determine an overall competitive level of compensation. The overall compensation levels, including the officer and non-officer short-term incentive compensation, are reasonable compared to the market. Compensation levels without these incentive payments would be below market competitive levels. Paying non-competitive levels of compensation would result in a lower qualified workforce that would not best serve customers. In order to hire and retain qualified personnel, it is necessary to either pay a competitive incentive or increase base salaries. The EICP incentive compensation costs are reasonable costs of doing business and, therefore, should be recovered in rates.

Use of annual incentive mechanisms is a recognized management technique for companies, including utility companies. As I discuss later in my direct testimony, incentive pay is the number one compensation design element used to influence short- to mid-term performance results. Incentive mechanisms help communicate priorities, engage the employees in operating and financial success, reward valued skills and behaviors, and create business understanding for employees. Consumers Energy's incentive programs are structured in a way that is designed to help keep non-officers and officers focused on operational performance areas as continuous improvement, safety, cost, reliability, and delivery. The incentive compensation program encourages employees to deliver their best performance and service for the Company's customers.

Q. Who is eligible for the EICP incentives?

A. All non-union employees are eligible for EICP incentives, with the exception of an employee who was rated as "under-contributing" or "needs improvement" on their annual performance appraisal. These under-performing employees are ineligible to receive an EICP incentive. Both non-officers and officers participate in an annual EICP.

Q. How are the EICP incentives structured?

A. The EICP incentives are structured by non-officer and officer EICP. The non-officer EICP equally weights the operational measures with the financial measures:

- Half (50.0%) of employees' incentive will be based on achievement of operational performance measures. (For 2018 and 2019, there are nine operational measures.); and
- Half (50.0%) of employees' incentive will be based on the achievement of two financial measures, Earnings Per Share ("EPS") and operating cash flow. Consumers Energy is a vital part of the Michigan economy and it is important that the utility remain financially strong so that it can provide the utility service that customers expect and deserve. Financial health also leads to reduced costs of capital and greater access to liquidity.

The goals are the same for the officer EICP, but the weightings are different. For the officer plan, the operational goals are a plus or minus modifier to the financial goals. I will discuss this difference in weightings later in my direct testimony.

II. EMPLOYEE COMPENSATION PHILOSOPHY

Q. What is Consumer Energy's philosophy about the overall level of compensation?

A. The Company's management believes Consumers Energy should pay a fair and reasonable salary, comparable to the market that is equitable to employees, consistent with Company values and strategies, and that supports the highest level of customer service at a reasonable cost.

Q. What are the components of Consumers Energy's compensation for non-officer employees?

A. There are two parts of overall compensation for non-officer employees of Consumers Energy. The first part is base pay. The second part for salaried employees is annual incentive compensation.

Q. What are the components of Consumers Energy's compensation for officers?

A. There are three parts of overall compensation for officers of Consumers Energy. The first two parts are cash compensation through base pay and annual incentive compensation. The third part is equity-based long-term incentive. As I mentioned earlier in my direct testimony, the Company is not seeking recovery for the costs of long-term incentive compensation in its rate recovery request in this case.

Q. Why does the Company make a portion of compensation subject to incentives?

A. A wide body of research supports the view that incentive pay (a variable pay component) works. One researcher states, "theory and research show that incentive pay can substantially increase individual and organizational performance, and can represent a powerful tool for establishing a competitive advantage within an industry." (Dow Scott, "Incentive Pay: Creating a Competitive Advantage" – WorldatWork Press, 2007). When properly selected and implemented, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. When goals are challenging yet achievable, employees are motivated to increase productivity and performance to achieve the goal. In addition, incentives increase a company's ability to attract, hire, and retain qualified and motivated individuals. A study by the International Society of Performance Improvement showed that incentive pay programs increase performance by an average of 22.0%. (International Society of Performance Improvement, "Incentives Motivation and Workplace Performance Research and Best Practices," Spring 2002). As stated by the Society of Human Resource Management:

> Research has demonstrated that some human resource programs and initiatives produce a significant impact on

> performance in organizations (as measured by factors such as quality, productivity, speed, customer satisfaction and unwanted turnover). The two initiatives that consistently showed statistically significant positive results were linking pay to performance and using variable pay. Research has established the potential of variable pay to produce the desired business results. [Robert Greene, "Variable Pay: How to Manage it Effectively, Society of Human Resource Management," April 2003.]

Consumers Energy has adopted incentives that are designed to emphasize operational performance criteria in areas that are critical to the Company's utility business and customers. Focusing employees on these goals provides both qualitative and quantitative benefits for Consumers Energy's utility customers.

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.

Q. How does Consumers Energy determine what level of overall compensation for non-officers is reasonable?

A. First, Consumers Energy's management targets overall compensation to the market median. Second, Consumers Energy's management actively reviews compensation levels so that employees are neither overpaid nor underpaid relative to market. Third, the Company uses a rigorous survey process which uses valid and reliable data from multiple sources to determine median levels of compensation. The fact that a portion of the compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. To the contrary, removing the incentive from employees' total compensation package, or failing to meet incentive performance goals, would render their compensation below-market.

Q. Would it be reasonable for Consumers Energy to pay employees below market level on an ongoing basis?

A. No.

Q. Why would it be unreasonable for Consumers Energy to pay below market level?

A. Consumers Energy has a responsibility to customers to employ a competent workforce that is ready, willing, and best able to provide service for our customers. Paying competitive wages and salaries is necessary in order to fulfill that commitment. It would not be reasonable or fair to the Company, its employees, or customers for the MPSC to set rates at a level that did not include reasonable levels of overall market-based compensation.

The level of service that customers deserve requires a qualified, experienced, and motivated workforce. The Company is able to attract, retain, and motivate talented employees when its overall compensation is competitive with market levels. A decision to compensate employees below market levels would detract from the Company's ability to assemble the committed and customer-focused workforce that customers deserve. Over time, this would be detrimental to customers, as well as being unreasonable to the Company's diligent, hardworking employees. Compensating employees below market levels will eventually result in them leaving for jobs that are paying at market levels. Over time, the workforce would tend to be less qualified, less experienced, less productive, and less capable of serving customers (as the most capable would, in general, tend to go to employers paying at competitive levels). This, in turn, could lead to less efficiency and could result in a need to hire more employees to produce the same service to customers, thus increasing costs to our customers.

Q. How does the Company determine the level of overall compensation for salaried non-officer employees?

A. For salaried non-officer employees, the Company uses salary survey data from utility and energy companies. Using this survey data, a benchmarking analysis of total compensation (base pay and incentive pay) is made between the Company's jobs and comparable survey jobs. Benchmarking analysis is a comparison of jobs commonly found in the labor marketplace and/or a job that is highly relevant/populated within a company. This comparison indicates where the Company's pay stands relative to the market. The Company's goal is to target overall pay levels within plus or minus 5.0% of the market median for non-officers. While pay for individuals inevitably varies from the survey market levels due to differences in experience levels, education, job performance, longevity, position responsibilities, etc., the survey data indicate that the Company's overall non-officer compensation levels, assuming the EICP payment at the target level, are on average within target pay level of plus or minus 5.0% of market median. Exhibit A-56 (AMC-2) provides a summary of average exempt and non-exempt pay for Company benchmark jobs compared to market using 2018 data for 2019 pay structure purposes.

Paying compensation that approximates the market median is particularly important given that Consumers Energy will continue to experience significant attrition and have a need over the next few years to hire engineers and other personnel to staff various projects and serve customers. The Electric Distribution Infrastructure Investment

Plan discussed by Company witness Richard T. Blumenstock presents a clear need for competitive, market-based compensation to attract and retain qualified, customer-focused employees to do this work. In competing for engineers, as well as other personnel that are skilled, high performing customer focused candidates, it will be important to have a reputation for paying a competitive level of overall compensation. Excluding the incentive target amounts would result in the Company's pay levels being approximately 5.0% to 10.0% below market level.

Q. How do you know the market data that the Company is using are appropriate and are not inflating salary levels?

A. The Company uses a number of survey sources to compare to the non-officer salaried workforce. The Company participates in and uses an industry survey performed by Willis Towers Watson, a well-respected, independent third-party compensation expert. This survey is conducted by surveying companies which report data on an anonymous basis. The data from Willis Towers Watson is the Company's primary source of compensation information. The Company also participates and uses EAP Data Information Solutions, LLC, an independent survey firm serving the energy industry, for non-officer hourly workforce market data. To supplement this data, the Company uses a reputable national on-line survey resource, CompAnalyst, which has survey data from a wide variety of independent sources. In every instance when using the survey data, the Company looks at the median total compensation (base pay and incentive) reported for highly populated jobs for which there is a comparable match. In this way, the Company is matching the relevant market, not trying to lead the market, and thus not inflating its overall compensation above prevailing market levels. The Company also looks at data from companies who are in the utility and energy industry, not data from high paying technology companies or pharmaceutical companies. By using three independent survey sources, the Company can determine if any one source is varying significantly from another.

Q. Can you give an example of the relationship between the Company's pay levels and the market's pay levels?

A. Yes. For the Company's Administrative Assistant III (75 employees) job, the Company's average salary plus incentive target (overall compensation target) is 9.5% below the market. For Administrative Specialist II (120 employees) the Company's level is 0.5% below the market. For Technical Specialist II (100 employees) the Company's level is 1.8% below the market. For Senior Technician (74 employees) the Company's level is 6.7% below the market. For Senior Engineer II (152 employees) the Company's level is 1.3% below the market. For Electric Field Leader (71 employees) the Company's level is 4.1% above the market. For IT Technical Senior Analyst II (93 employees) the Company's level is 7.0% above the market. For Senior Business Support II (91 employees) the Company's level is 2.4% above the market. For Senior Engineering Technical Analyst II (74 employees) the Company's level is 4.7% above the market. These nine jobs are among the most highly populated of Consumers Energy's salaried workforce.

Q. Are incentive plans common in the utility industry?

A. Yes, incentive plans are quite common. Annual incentive programs are a critical and highly integral part of competitive compensation packages for many organizations. Research from Willis Towers Watson's 2012 Survey Report indicates that approximately 80.0% of companies offer annual incentive (variable pay) programs. That number is slightly higher at 81.2% for those companies within the utility industry sector. The survey data supports the conclusions that including incentive pay as part of a competitive pay package is a standard industry practice and is required to attract and retain good employees.

Research from Mercer's 2014/2015 U.S. Compensation Planning Survey Report indicates that approximately 83.0% of companies offer annual incentive (variable pay) programs. For companies within the utility industry sector, the survey indicated that 98.0% of executives, 99.0% of management, 94.0% of non-sales professionals, and 86.0% of clerical and technicians were eligible for an annual incentive.

A 2012 Mercer study of more than 1,200 organizations reveals that actual company spending on variable pay for salaried exempt employees, as a percentage of pay, is 12.0% and salaried/hourly non-exempt employees, as a percentage of pay, is 6.0% to 7.0% for energy companies. A 2009 Hewitt Associates study of more than 1,100 organizations further reports that companies were budgeting variable pay for salaried exempt employees at 11.8%, and 5.5% to 6.1% for salaried/hourly non-exempt employees, for 2010. Ken Abosch, leader of Hewitt's North American Broad-Based Compensation Consulting business, added:

> Over the past decade, we've seen companies steadily shift from a fixed pay model to one that emphasizes true performance-based awards, and we expect this trend will continue.

Consumers Energy's practice of making a portion of overall employee compensation subject to incentives is consistent with best practices for compensation.

Q. What has been the trend in variable or incentive pay?

A. A 2016 study by Aon Hewitt indicated a 72% growth in variable pay spend over the past 20 years. Variable pay grew from 4.1% of base salaries in 1996 to 12.9% of base salaries in 2015. Business incentive plans are the most prevalent with 77% of companies using this type of variable pay award in 2015 up from 55% in 1996. Business incentive plans refer to plans that are based on Company financial and/or operational goals.

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 4,400 employees (total utility) that 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 of 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. The EICP target level for each pay grade was established by measuring the difference between the Company's base salary target and the market's overall compensation level.

The EICP compensation is part of the overall market-based competitive level of compensation, not in addition to it.

Q. Explain if the Company reduced base pay when it started to pay incentive awards in order to obtain market-based pay based on the combination of the two components of pay.

A. The Company has always had a broad-based incentive compensation plan in place for salary grades 19 and above. In 2003, an EICP for employees in salary grades 18 and below 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 was $50,000 for a hypothetical job and market base average pay was $50,000 plus a $2,000 incentive award, then the Company would need to offer $52,000 to match the market's current pay. So, the alternative to having an incentive component of overall compensation would be to raise base pay to the market's overall compensation. Eliminating incentive pay would result in the same compensation costs, but employees would lose focus on continuous improvement, safety, quality, cost, reliability, and delivery to the customer. Increasing base pay would also result in a higher level of fixed costs tied to base pay, such as certain pension and defined contribution benefit plans, life insurance, disability insurance, and other salary-based employee benefits.

The Company's overall compensation needs to be comparable to the market for salaried employees regardless of whether it is composed of only base pay or composed of base pay plus the target incentive award amount. The Company has maintained overall compensation at competitive levels through the incentive plan. But for the incentive plan, the Company's non-officer base salaries would be less than overall competitive market-based compensation levels.

Q. Would elimination of incentive pay be in the best interests of customers?

A. No. With incentive compensation, the employees and the Company as a whole must re-earn the at-risk compensation each year. If high levels of performance are not met each year, incentive pay can be reduced or eliminated. The elimination of variable "at-risk" pay would create a situation where all compensation is guaranteed and would remove an important incentive to improve service. This result would be counter to customer interests.

Q. How does the Company determine the level of overall compensation for officers?

A. A utility must maintain a competitive total compensation package in order to attract and retain executive talent. As discussed above, Consumers Energy creates a compensation package for officers that delivers base salary, annual incentives, and long-term incentives (excluded from the Company's request in this rate case) targeted at the 50th percentile of the market, as defined by a Compensation Peer Group approved by the Compensation Committees of the Boards of Directors. The Compensation Peer Group consists of energy companies comparable in business focus and size to CMS Energy with which the Company might compete for executive talent. The Compensation Peer Group currently includes 18 companies.

Q. How do you know the market data that you are using for officer compensation are appropriate and are not inflating salary levels?

A. Annually, the Compensation Committees engage an independent third-party consultant to provide advice and information regarding compensation practices of the Compensation Peer Group as well as additional information from published surveys of compensation in the public utility sector and general industry. During the Compensation Committees' review of officers' compensation levels, consideration is given to the advice and information received from the independent compensation consultant; however, the Compensation Committees are ultimately responsible for determining the form and amount of the compensation programs.

Where available by position, Compensation Peer Group data serves as the primary reference point for pay comparisons of utility specific roles, and broader survey data and published proxy data are also provided by the compensation consultant as a point of reference for utility specific roles and comparisons of general industry roles. Where available by position, Pay Governance gathers compensation data from Willis Towers Watson's Energy Services Executive Database (over 50 investor-owned utilities) and Willis Towers Watson's General Industry Executive Database (approximately 500 participating companies), which it regresses based on CMS Energy's revenues to provide additional market context to the Compensation Peer Group. In selecting members of the Compensation Peer Group, financial and operational characteristics are considered. The criteria for selection of the Compensation Peer Group included comparable revenue;

relevant utility industry group; similar business mix (revenue mix between regulated and non-regulated operations); and availability of compensation and financial performance data.

The survey data indicate that the Company's overall officer compensation levels, assuming the EICP and restricted stock payment at the target market-based level, are reasonable.

In addition, annually proxy advisor services Glass Lewis & Co. and Institutional Shareholders Services assist institutional investors in their advisory vote on the reasonableness of compensation pay and practices of the proxy-named executive officers by providing a vote recommendation. The incentive pay practices for the proxy-named executive officers are the same as for the remaining officer group. In 2019, both proxy advisory service firms recommended a vote "for" the proxy-named executive officer compensation pay and practices. Also, Shareholders voted 98% in favor to approve executive compensation as described in the 2019 Proxy Statement.

Q. Does the independent consultant provide other services for CMS Energy or Consumers Energy that could result in a conflict of interest?

A. No. The independent consultant is required to obtain approval of the Compensation Committees of the Boards of Directors before undertaking any activity on behalf of the management of CMS Energy or Consumers Energy. During the time the consultant has been engaged as the compensation consultant for the Boards of Directors, it has not performed any services on behalf of the management of CMS Energy or Consumers Energy. The independent consultant is hired by and serves the Compensation Committees; it is not hired by or providing services to CMS Energy or Consumers Energy.

Q. Are surveys the only determining measure used in setting officer compensation levels?

A. No. Additionally, the Compensation Committees consider experience levels and individual contributions of the respective officers.

Q. Are incentive plans for officers common in the utility industry or in other industries?

A. Yes, incentive plans are prevalent. Research from Mercer LLC, U.S. Compensation Planning 2014/2015 survey indicates that approximately 96.0% of companies, and 98.0% of energy companies, offer annual incentive (variable pay) programs for officers. The survey data support the conclusions that including incentive pay as part of a competitive pay package is a standard practice and is required to attract and retain qualified officers.

III. INCENTIVE COMPENSATION PLANS

A. Description of Incentive Plans

Q. Please describe the EICP that is in place for 2019.

A. The EICP for 2019 is based on achieving performance goals related to critical areas of the Company's operations. The goals focus on continuous improvement measures and maintaining financial health in order to deliver value benefits to our customers. The Company's EICP goals seek to encourage employees to provide reliable energy, customer value, and responsive service to our customers, and to do so safely. Each year, the Company establishes utility specific performance criteria which focus on continuous improvement goals and breakthrough goals. For 2019, there are nine specific operational performance measures and two measures related to being financially healthy. The EICP Performance Measures are summarized on Exhibit A-55 (AMC-1).

Q. Please describe Exhibit A-55 (AMC-1).

A. Exhibit A-55 (AMC-1) identifies the operational performance and financial performance areas that the EICP focuses on and identifies the specific measures that have been adopted for each of these areas. In the last column the year-end target is identified. As I indicated earlier, 50.0% of the non-officer incentive compensation is based on operational performance and the remaining 50.0% is based on the financial performance.

Q. Will the structure of the EICP goals for 2020 be similar to 2019?

A. The specific performance measures and targets for 2020 have not been finalized yet. However, as in prior years, the performance measures will be a combination of measures related to operational performance and financial health. I anticipate that, as for 2019, for non-officers the operational performance and financial health goals will be weighted equally. I anticipate that for officers the attainment of the financial measures will again be a threshold component with the operational goals as a modifier.

Q. Will the performance measures continue to incorporate measures that provide benefits to Consumers Energy's customers?

A. Yes. Performance measures will continue the focus on world class performance delivering hometown service and will continue to have as their foundation continuous improvement and breakthrough measures. While the number and precise phrasing of operational and financial performance measures may vary from 2019, areas of focus will continue to include employee safety, public safety, reliability, cost, delivery, customer care, and financial health.

Q. Please discuss the strategy and process for developing the EICP goals.

A. Company witness R. Michael Stuart provides a discussion of the strategy and process for developing the EICP goals.

Q. Why has the Company's management chosen to design the EICP with broad goals and objectives on a Company-wide basis rather than individual goals and objectives for individual employees?

A. It is necessary and appropriate for a large organization, such as Consumers Energy, to establish broad goals and objectives that are communicated to all employees as matters that are important to the success of the organization. Some employees will be in a better position to influence whether particular goals and objectives are met, but having every employee linked to a set of common customer-focused objectives is an effective method for emphasizing the importance of customer value and service. Having common goals and objectives: (i) provides clear communication of Company goals; (ii) encourages employees to support each other and work together for common goals; and (iii) provides a scorecard with a focus on corporate-wide goals that benefit customers.

Consumers Energy incorporates individual goals through the annual performance feedback process, which includes the creation and review of individual goals and objectives for each salaried employee and the opportunity to recognize and reward individual performance. The existence of a common set of customer objectives enables supervisors and employees to establish individual goals and objectives which are supportive of, and in alignment with, the corporate goals reflected in the EICP.

Q. How are the payout levels set that are shown on Exhibit A-55 (AMC-1)?

A. When setting payout levels, threshold is set at a level of achievement that can typically be reached eight or nine times out of every ten years. Maximum payout is for exceptional performance (one to two times out of every ten years). These levels are to engage the employees in meeting the goals. Employees, as a whole, must re-earn the incentive at-risk portion of compensation each year. If the threshold to achieve a payout was set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in fewer customer benefits. Overall compensation levels, including the EICP at target (100%) level that Consumers Energy seeks are not excessive. It is reasonable for Consumers Energy to pay its employees competitive levels of compensation.

Q. Should a refund mechanism be used for goals that are not achieved?

A. No. The goals are a collective package and the results should not be looked at in isolation. In fact, it would be wholly inappropriate to do so. The approach of looking at the goals as a complete package encourages improved performance and greater efficiencies from employees from which customers benefit. Further, the Company is only requesting that target level performance be included in rates.

Q. Why are you including both gas and electric performance measures in this plan as this is an electric rate case?

A. For purposes of efficiency and improved service, the Company has combined operations as one organization. For that reason, the plan contains both gas and electric measures.

Q. Are the two financial performance goals that are included in the EICP measures consistent with the Company's responsibilities to its customers?

A. Yes. Consistent financial performance is the result of total company performance including achieving operational success. Company witness Stuart quantifies this customer benefit for operating metrics in his direct testimony in this case. Also, an analysis of the cost of capital is discussed by Company witness Todd A. Wehner in his direct testimony and Exhibit A-14 (TAW-1), Schedule D-5, page 7, in this case. Having a financially healthy utility is important to delivering the energy our customers need when they need it and to the state of Michigan as the Company is a vital part of the economy. It is in the customers' interests to have a financially healthy utility. This allows the utility to better meet customer needs at the best price. The two financial goals are balanced with operational performance criteria. Financial goals help focus employees on achieving superior results in a cost-effective manner. By focusing employees' attention on goals that encourage improved performance and greater efficiencies, customers are benefited. The incentive compensation goals are designed to help motivate employees to perform at their full potential and exercise discretionary effort to help move the Company forward.

Q. How are the targets for the annual officer EICP incentives measures determined?

A. As mentioned earlier, the goals are the same for the officer and non-officer EICPs, but the weightings are different.

Q. Why is the weighting different for the officer plan?

A. Officer annual incentive awards are based on the achievement of EPS and operating cash flow goals. These two metrics are good indicators of strategy execution. The officer annual incentive award is reduced if there is no award earned under the operational performance measures portion of the EICP and the award is increased (but in no event shall the award exceed the maximum of the target annual incentive) if the maximum award payout is achieved under the operational performance measures portion of the EICP. This potential adjustment provides linkage of executive compensation with the goals related to operational performance.

Q. How are the EPS and operating cash flow components determined?

A. EPS is determined in accordance with: (i) generally accepted accounting practices; (ii) excluding asset sales; (iii) changes in accounting principles from those used in the budget; (iv) large restructuring and severance expenses greater than $5 million; (v) legal and settlement costs or gains related to previously sold assets; (vi) Federal tax reform; and (vii) regulatory recovery for prior year changes. Cash flow means: (i) generally accepted accounting principles operating cash flow with adjustments to include changes in power supply cost recovery from budget (disallowances excluded); (ii) changes in pension contribution; (iii) changes in accounting principles from those used in the budget; and (iv) gas-price changes (favorable or unfavorable) related to gas cost recovery in January and February of the following performance year. The Compensation Committees review management's preliminary recommendations and establish final goals.

Q. Is operating cash flow a duplicative financial measure to EPS?

A. No. While earnings and cash flow are related, they are not the same. EPS is a measure of profit generated by a company's daily operations. The figure includes revenues and expenses. Some of the expenses used to calculate earnings are considered "non-cash" items, such as depreciation and amortization, and do not impact cash flow. Moreover, select financing decisions made by the Company such as issuing or repurchasing stock can have a direct impact on EPS without impact to operating cash flow. The operating cash flow is a measure of cash generated from operations and what is needed to make investments in the utility. The cash flow measure in the incentive plan starts with generally accepted accounting principles operating cash flow and then it is adjusted as discussed earlier in my direct testimony.

Q. How are the target amounts for the annual officer incentives determined?

A. The Compensation Committees determine the target amounts of the annual officer incentives. In determining the amount of target incentives, the Compensation Committees consider the following factors:

- The target incentive level, and actual incentives paid, in recent years;
- The relative importance, in any given year, of each performance goal established; and
- The advice of the Compensation Committees' compensation consultant as to compensation practices at other companies in the Compensation Peer Group and the utility industry.

B. <u>Assessment of Customer Benefits of the Incentive Compensation Plans</u>

Q. What level of expenses for Consumers Energy's incentive plans has been included in the "test year" revenue requirement?

A. The Company is requesting recovery of electric O&M expenses related to EICP incentive compensation plans at target (100.0%) levels. The level of expense is approximately $5.2 million as illustrated in Exhibit A-57 (AMC-3). Incentive compensation for the proxy officers is not included in these amounts.

Q. How are the electric expenses of $5.2 million related to annual incentive compensation calculated?

A. The $5.2 million for EICP incentive compensation is based on the following:

- For officers: The rate case expense amount is based on 2018 salaries (excluding the proxy officers) multiplied by the approved target incentive percentage of salary from the 2018 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) and forecasted salary increases (increase expense), as indicated below; and

- For non-officers: The rate case expense amount is based on an estimate of the number of employees in each salary grade multiplied by the plan prescribed incentive target amount. Progression to higher salary grades 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?

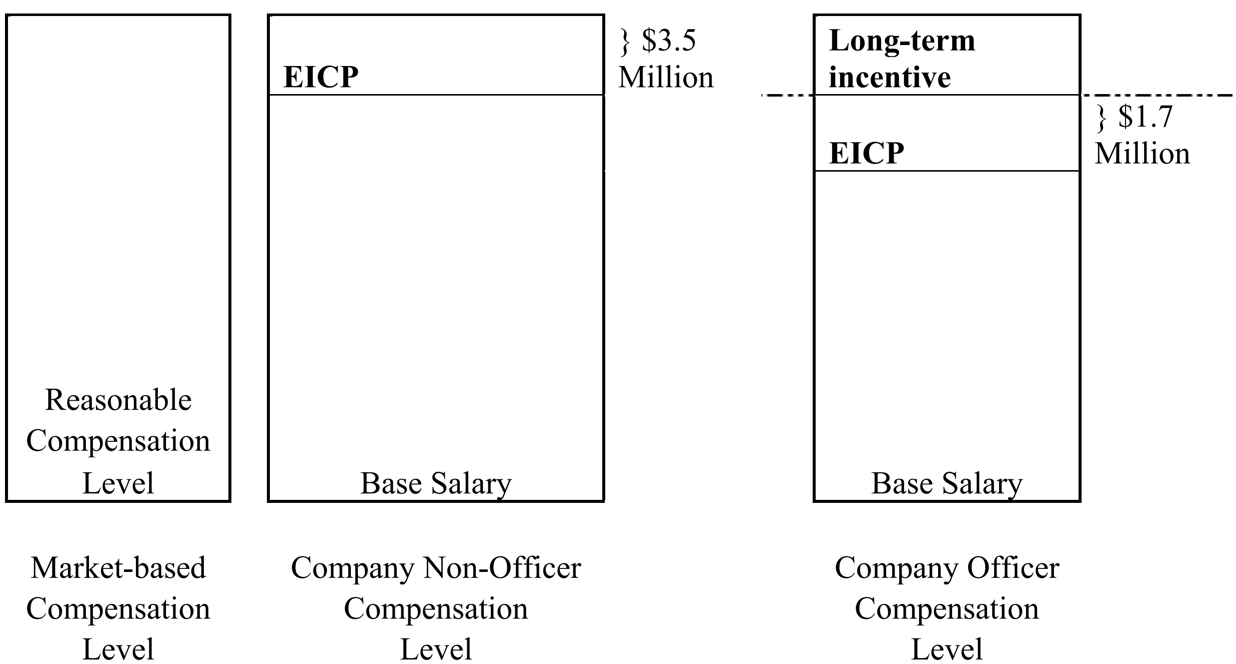
A. Yes. In the Company's 2014 Electric Rate Case, Case No. U-17735, the Commission issued an Order on November 19, 2015 approving the recovery of annual incentive (EICP) in rates for non-officers and non-proxy officers. As a result, in the first quarter of 2016, the Company began classifying annual incentive expense for the approved employee groups as a labor cost. The labor costs charge between O&M and capital based on labor studies performed by each business unit.

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 his or her position by contributing to the achievement of performance measures. Customers receive both qualitative and quantitative benefits at no additional cost above market-based compensation.

Q. Why do you say there is no additional cost above market-based compensation?

A. The officer and non-officer incentive plans are designed so that the total base salary plus incentive payments will be equivalent to the market-based compensation level. The EICP is part of the overall reasonable level of market-based compensation. It is not in addition to it. This is illustrated in the following diagram:



Q. What is the appropriate standard from a business perspective in evaluating the reasonableness of the EICP costs?

A. Making a portion of compensation subject to incentives is a recognized, well-established, common practice in the utility industry and is reasonable and appropriate. The appropriate standard from a business perspective in evaluating whether the level of compensation is reasonable is whether the *overall* level of compensation, including both base salary and incentive compensation, is reasonable. Using this standard would also be appropriate for ratemaking purposes. Looking at whether the overall level of compensation is reasonable will provide a better indication of whether the incentive plan results in excess rates than attempting to examine the cost allocable to the incentive compensation compared to benefits to customers. The overall level of compensation that Consumers Energy has included in its request in this case is reasonable.

Q. Under the Company's proposal, do shareholders bear a portion of the EICP costs?

A. Yes. The Company's incentive compensation proposal in this case does result in shareholders bearing a portion of incentive costs. The Company's proposal to include incentive compensation costs at target levels will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target level. Thus, shareholders will absorb any resulting increase in costs arising from above target performance. If actual payouts in future years are less than target levels due to inadequate financial performance, then the Company's shareholders will absorb the consequence of inadequate performance results along with customers. In addition, the proposal in this case excludes the expenses related to the named officers in the proxy statement. The Company is allocating to shareholders 100% of the costs of incentive compensation for the proxy officers as identified by the SEC proxy rules.

Q. If the Commission concludes that customers should not pay 100% of the portion of the EICP costs that relate to financial measures due to shareholder benefits is the exclusion of 100% of incentive plan costs that relate to financial measures from the revenue requirement warranted?

A. No. While the Company believes that 100% recovery from customers of the portion of the EICP costs that relate to financial measures is appropriate for the reasons discussed above, a 50/50 sharing of the portion of the EICP costs that relate to financial measures should be adopted rather than a complete disallowance of those costs. This approach provides a balanced approach to controlling costs (financial measures) and efficiently serving customers (operational measures) which both benefit customers. Financial and operating goals are not mutually exclusive.

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 reasonable and is in the best interests of the Company's customers. Incentive compensation does not result in excessive compensation and is reasonably necessary to attract, retain, and motivate a talented workforce to serve our customers. Further, gaps between the skills that employers require and those available in the labor market are growing. Paying a reasonable level of compensation which includes incentive compensation is necessary to attract, retain, and motivate a talented workforce.

Q. Is the EICP a bonus or profit sharing plan?

A. No. The EICP is not a bonus or profit sharing plan. A bonus is a discretionary payment given without predetermined goals or objectives and a profit sharing plan entitles employees to a share of the profits of the Company without pre-determined goals or objectives and is not part of total cash compensation market levels. Consumers Energy offers incentive compensation, which is based on predetermined goals and objectives and award levels. Incentive compensation is part of an employee's overall compensation and not in addition to it, like a bonus or profit sharing plan. The fact that a portion of compensation is in the form of an incentive payment does not mean that employees are paid in excess of market rates when they receive their incentive payment. Employee compensation is a reasonable cost of doing business. If overall compensation levels are reasonable, then those costs should be recoverable through utility rates.

Q. What are some of the ways the EICP incentives benefit customers?

A. Customers derive benefits by having a portion of compensation shifted to the EICP Program since the goals of the program are in the interests of customers. Customer benefits are achieved without any additional cost to customers since this program has been structured as a "carve out" of the employee's base salary. If the EICP costs had not been allocated to incentive compensation, those costs would need to be recovered as base compensation in order 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 as a whole must re-earn the incentive award every year. If performance goals are not achieved, cash compensation is reduced or eliminated. Variable pay creates a performance culture rather than an entitlement culture.

In addition, an incentive program structured to focus employee attention on operational performance results in both qualitative and quantitative customer benefits. Among other things, customers benefit from increased cyber security, reliability, and on-time delivery and the focus on employee and public safety that helps reduce potential increased costs.

A quantitative analysis of the benefits received by the customer as a result of the EICP is discussed by Company witness Stuart in his direct testimony in this case.

Further, customers are best served when Consumers Energy can raise capital at the best available rates. The use of earnings and cash flow measures in the EICP and officer annual incentive recognizes that Consumers Energy's financial health is important. Financial health provides appreciable benefits to customers by allowing Consumers Energy to maintain an attractive cost of capital and broader access to liquidity, in addition to any benefits provided to investors. An analysis of the cost of capital is discussed by Company witness Wehner in his direct testimony in this case.

Q. How do customers benefit from the focus on employee safety?

A. Customers directly benefit from having a qualified, talented, and motivated workforce that is focused on areas such as safety. The incentive compensation program encourages employees to deliver their best performance for customers. This is illustrated in the area of safety. For seven of the last twelve years, incidents have decreased: 558 in 2007, 355 in 2008, 258 in 2009, 207 in 2010, 149 in 2011, 119 in 2012, 137 in 2013, 150 in 2014, 106 in 2015, 73 in 2016, 65 in 2017, and 102 in 2018. This decrease from 2007 to 2018 of approximately 82% can be directly attributed to the significant emphasis Consumers Energy has placed on safety during this period. The decrease in safety incidents helps reduce lost days and helps reduce medical costs from levels that would otherwise occur. The safety components of the EICP performance measures have been an important part of keeping all employees focused on safety. This is an example of how all employees can be motivated and engaged in achieving a common Company goal through use of the EICP.

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 $5.2 million for the test year. The benefits illustrated in Company witness Stuart's testimony are $21.4 million, which shows that the benefits to customers of the Company's EICP Program outweigh the costs of the program. Since this amount is part of the overall level of reasonable compensation, rather than being in addition to it, all benefits to customers are achieved at zero additional cost to customers. Achievement of the Company's EICP goals and objectives result in pay that is competitive with the labor market, not above the market. The EICP costs are not in addition to the reasonable level of compensation, they are part of the reasonable level of market-based compensation. If these amounts are not paid, then overall compensation would be at a level which is below the market level. There is no valid basis to eliminate incentive costs from the cost of service recovered in rates because they are a part of an incentive plan rather than including these costs as part of base pay. As stated before, overall levels of compensation are at levels that are not excessive. Rate recovery of 100.0% should be allowed.

IV. <u>CONCLUSION</u>

Q. Is the Company's overall compensation program, including the customer-focused incentive, reasonable?

A. Yes. The approach used by the Company is a reasonable approach, is consistent with industry standards, and represents well-established best practices for creating customer focus through compensation design, and it does so without any additional customer cost above the market. The overall compensation levels are reasonable relative to the market, are determined in a reasonable manner, and are a reasonable cost of doing business. Compensation is structured in a manner that rewards improved operational and financial performance that benefits customers. The incentive compensation costs should, therefore, be included in the cost of service recovered from customers. These are legitimate and reasonable costs of doing business. Rates established in this rate case should include approximately $5.2 million for incentive compensation expense.

Q. Please summarize reasons why full recovery of incentive compensation costs should be allowed in this case.

A. Reasons that full recovery of compensation costs should be allowed include the following:

- Employee compensation is a reasonable cost of doing business, has been set at a reasonable level, and has been determined using a reasonable methodology;
- The amount of compensation that is subject to incentive measurements is part of the market-based compensation level, not in addition to it;
- The incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce to best serve the customer;

- Making a portion of compensation subject to incentives is a recognized, well-established, and common industry practice and is neither irrational nor unreasonable;
- The decision of Consumers Energy to allocate a portion of overall compensation that would otherwise have been in base pay so that it is subject to incentives does not provide a valid basis to disallow these expenses;
- The plan incorporates operational as well as financial performance goals;
- Quantitative and qualitative customer benefits of having a portion of compensation subject to incentives occur at no additional cost above market-based compensation to customers given the compensation structure adopted;
- Investors, including shareholders, bear the expense of incentive compensation in excess of the target levels and for incentive compensation provided to proxy officers; and
- The focus should be on whether the overall level of compensation is reasonable, not on the precise structure of the compensation program.

It is reasonable for Consumers Energy to pay its employees competitive levels of compensation. Paying employees at competitive market levels is reasonable and prudent. Those incentive pay costs are reasonable costs of doing business and are recoverable from customers. Since the total level of compensation – including both base pay and incentive pay – is market-based, competitive, and reasonable, incentive pay expense is justified and recoverable. Customers do not pay more than the reasonable level of market-based compensation.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

MICHAEL J. DELANEY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

MICHAEL J. DELANEY
DIRECT TESTIMONY

I. Witness Background Section

Q. Please state your name and business address.

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

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Executive Director of Regulatory Affairs and Policy, in the Rates and Regulation group.

Q. Please describe your educational background.

A. I received a bachelor's degree in Engineering Physics from the University of Michigan in 2002, a master's degree in Nuclear Engineering from the Massachusetts Institute of Technology in 2004, and a Master of Public Policy from the Gerald R. Ford School of Public Policy from the University of Michigan in 2007.

Q. Please describe your professional experience.

A. I previously was employed at DTE Energy Company ("DTE") in 2006, starting as a senior analyst in the Corporate Strategy and Mergers and Acquisitions group. At DTE, I served in roles of increasing responsibility. This included time as an Associate in DTE Energy Ventures, where I evaluated a wide range of clean energy startup companies and managed a $5 million electric vehicle research and implementation grant in partnership with General Motors and the University of Michigan. This grant was awarded by the Michigan Public Service Commission ("MPSC" or the "Commission") in 2008. I moved into DTE's Corporate and Government Affairs organization in 2010, serving as Supervisor of Public Policy from 2010 to 2012, Manager of Strategic Initiatives from 2012 to 2014, and

Manager of Policy Strategy and Advocacy from 2014 to 2016. In these roles, I was responsible for enterprise strategy development in a range of state and federal policy issues.

I joined Consumers Energy in 2016 as the Director of Research and Analysis. In this role I was responsible for monitoring the Company's external business environment and performing research and analysis in support of the Company's long-term strategy. In 2017, I was promoted to Executive Director of Corporate Strategy. As Executive Director of Corporate Strategy, I led the team responsible for an analytically rigorous "signpost" and scenario planning process to understand and adapt to significant changes in the utility industry; the Company's long-term strategic planning process; and internal strategic consulting on high-priority assignments at the direction of the senior executive team.

In August 2018, I was promoted to my current role.

Q. What are your responsibilities as Executive Director of Regulatory Affairs and Policy?

A. I lead teams that serve as the Company's primary interface with the Commission, engage and collaborate with regulatory stakeholders, and advance Michigan's utility industry. My team also provides project management for the development of major Company regulatory filings. Additional responsibilities include strategic consulting and analysis on a wide range of state and federal public policy issues. The overarching role of our team is to advance the Company's triple bottom line vision, as described in more detail by Company witness Michael A. Torrey.

Q. Have you previously testified before the Michigan Public Service Commission?

A. Yes, I have filed testimony on behalf of the Company in Case No. U-20134.

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

Yes, I am sponsoring the following exhibits that were prepared by me and under my direction:

Exhibit A-58 (MJD-1)	Conservation Voltage Reduction Program Benefits and Costs (2021-2025); and
Exhibit A-59 (MJD-2)	Conservation Voltage Reduction Regulatory Return Comparison.

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

A. Yes, they were.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to introduce the Company's proposal to establish an incentive as part of its Conservation Voltage Reduction ("CVR") Program and highlight the benefits of encouraging cost-effective utility programs that provide significant customer value. The Company's CVR Program offers significant societal and environmental value, providing customers with a direct cost reduction when compared to alternative resource investments. Although the CVR Program provides this high value proposition to customers, investment in CVR also results in lost revenues and a lost earnings opportunity for the Company.

The CVR Program reduces energy usage and replaces the need for prudent investments in supply-side resources that provide a return under the traditional utility business model. The Company's proposed CVR incentive in this proceeding encourages utility innovation that creates societal and environmental value – as well as quantifiable utility customer cost savings. Customer benefits from CVR have not been fully realized. The Company's proposal is similar to the Energy Waste Reduction ("EWR") approach where customers and utilities share in the savings created through program implementation. As discussed in more detail below, the Company's CVR shared savings proposal creates a win-win opportunity that will benefit customers, the Company, and the state of Michigan.

Q. How is your direct testimony organized?

A. My direct testimony covers four key components:

- Customer Benefits from the CVR Program;
- Asymmetries between CVR Program value and shareholder value;
- Aligning Value - Shared Savings Incentive Mechanism; and
- Long-term value and future innovation.

II. CVR Program Benefits for Customers

Q. Briefly describe customer benefits associated with the CVR Program.

A. As the Commission has previously recognized, there are significant customer and public interest benefits associated with the Company's CVR Program. CVR facilitates system voltage reductions that in turn lower the amount of energy consumption on the electric system. CVR deployment creates multiple value streams that can best be characterized by the following categories:

Capacity Production

The CVR Program reduces annual electric demand. This results in reduced capacity costs by avoiding the need to maintain, build, or procure new capacity resources.

Energy Production

Similarly, the program reduces annual electric usage. The reduction in energy results in avoided supply costs from generation and/or wholesale market purchases.

Transmission

Reducing energy production correspondingly reduces transmission system usage and allows for reduced transmission needs and the potential to defer or avoid additional transmission system investments.

Distribution

Decreasing the use of the distribution system extends the system's useful life and allows for avoidance (or deferment) of distribution system upgrades.

In addition to economic value for customers, CVR offers meaningful environmental benefits. As noted in the Company's Integrated Resource Plan ("IRP") in Case No. U-20165, cost-effective demand side resources, including CVR, serve as replacement capacity as other resources, such as D.E. Karn Units 1 and 2, are retired.

Q. How does the CVR Program enable these benefits?

A. CVR uses a series of technologies that reduces the delivery voltage along electric circuits. The reduction of delivery voltage then reduces the amount of electric load that must be served on the electric system. Company witness Richard T. Blumenstock explains how enhanced distribution system capabilities, including CVR, are key components of the Company's grid modernization strategy.

Q. How do customer benefits compare to the program costs?

A. The Company's CVR Program is a cost-effective resource for customers. As depicted in Exhibit A-58 (MJD-1), the benefits of CVR exceed program costs in each program year. By 2025, the CVR Program is expected to generate approximately $18.6 million avoided cost benefits. Specially, as demonstrated in Exhibit A-58 (MJD-1), in 2025 there are projected $9.2 million in benefits from reduced generation capacity costs and $7.2 million from avoided supply costs (from generation or wholesale market purchases). Additional customer benefits of $2.2 million are realized from avoided transmission and distribution costs.

The revenue requirement for the program, as shown in Exhibit A-58 (MJD-1) is expected to be approximately $2.3 million in 2025, with approximately $1.9 million related to capital investments in the distribution system and the remaining $0.4 million related to operations and maintenance ("O&M") expenses.

After accounting for program costs and the Company's proposed incentive (which will only occur if there is demonstrated customer savings), customers are expected to realize approximately $13.8 million in savings in 2025. The Company's CVR Program with the proposed incentive is cost-effective for customers.

Q. Are these benefits different from energy efficiency and demand response?

A. Yes. While energy efficiency reduces energy consumption and demand response supports avoided (or delayed) capacity investments, both programs require action by customers to achieve energy and capacity reduction benefits. In contrast, CVR is a utility-side efficiency program that does not require any customer behavior changes. Customers do not need to participate to receive program benefits. Service quality is not negatively impacted by the CVR Program.

Q. How are the CVR benefits measured and calculated?

A. Company witness Blumenstock provides an overview of the metering equipment and methodology for measuring energy and capacity savings due to the deployment of the CVR Program. The Company has calculated the benefits associated with these savings using the same approach that the Commission has approved for use in the Company's EWR programs. Specifically, the savings are measured through an evaluation of the avoided energy and capacity costs relative to the cost of implementing the CVR Program.

Q. Why was the EWR methodology selected to calculate program benefits?

A. The methodology utilized in the Company's EWR proceedings is straightforward and was developed through previous contested proceedings, where stakeholder comments and feedback shaped this approach. Similar to EWR, the energy and capacity savings from CVR are realized through a reduction in customer energy usage, measured at a customer's electric meter.

<u>Asymmetries of CVR benefits</u>

Q. What impact does measurable load reduction, driven by CVR, have on the Company?

A. While offering a high value proposition for customers, the CVR Program also results in lost earnings opportunities for the Company. CVR is expected to reduce annual electric usage by 184,491 MWh in 2025 as shown in Exhibit A-58 (MJD-1). Electric sales will correspondingly decrease. Reduced energy and capacity reduce the need for distribution and generation capital investments.

By aggressively pursuing nascent CVR technology for the benefit of customers, the Company is forgoing the opportunity to invest in other resources that would provide more financial upside to the Company's shareholders. The Company, from purely a financial perspective, is better off investing in a more traditional and proven, supply-side resource to meet both customers' capacity needs and shareowner expectations.

Q. How does utility investment in CVR compare to other traditional supply-side resources?

A. There is a significant gap in earnings opportunity between a supply-side resource and CVR investments. Absent an incentive, CVR is expected to provide a potential return on capital investment of approximately $1 million in 2025 (Exhibit A-58 (MJD-1), line 16). In contrast, procuring solar resources with comparable energy and capacity outputs (consistent with the Company's recently approved IRP) provides an earnings opportunity in 2025 of $5.3 million. The earnings opportunity increases to $9.4 million if the Company were to own 100% of a comparable solar resource.

The earnings gap widens over a longer time horizon. The net present value return opportunity of the Company's supply side alternative to CVR from 2021 through 2040 is $41.2 to $71.4 million, in contrast to only $8.1 million for CVR, as reflected in Exhibit A-59 (MJD-2). There is a significant gap between customer benefits from CVR and the return available to the Company under the traditional utility earnings model.

Q. How can the Commission encourage investment in CVR?

A. The value and benefits to CVR are not yet fully realized in Michigan or at a national level. CVR implementation across the nation has been primarily limited to small pilot programs and a handful of municipal and cooperative utility programs. The Commission has an opportunity to make Michigan an industry-leader in CVR deployment.

Financial incentives for energy efficiency in Michigan have taken insignificant programs and expanded utility investment in valuable waste reduction programs. Customer savings have exponentially increased since EWR financial incentives were established, and later increased, by the Michigan Legislature. Like energy efficiency, the traditional earnings model for utility investments does not fully appreciate the customer, societal, and environmental value created by CVR.

Several years ago, the National Association of Regulatory Utility Commissioners issued a resolution encouraging state regulatory commissions to develop mechanisms to ensure that utilities and their customers are not financially burdened as a result of energy and demand reductions associated with voltage optimization deployment. The resolution added that such mechanisms can be used to avoid barriers to voltage optimization technology deployment.

In this case, the Commission can take an innovative approach and encourage CVR investment through a shared savings incentive mechanism. A shared savings incentive mechanism recognizes CVR program benefits and encourages utility innovation to develop future customer savings opportunities. As explained in more detail below, the Company is proposing a shared savings mechanism of 15% of the customer benefits that will be realized through CVR implementation. The Company would only be eligible for an incentive if customers receive MW and MWh savings.

The proposed incentive mechanism will encourage utilities to look to system optimization for new and innovative ways to find savings opportunities for customers. As proposed in this case, the shared savings incentive places CVR on a level playing field with traditional utility capital investments. The proposed shared savings mechanism is a win-win approach for the Company and its customers.

Shared Savings Proposal

Q. Please provide an overview of the proposed CVR incentive.

A. The Company is proposing a shared savings incentive mechanism that would allow the Company to share 15% of actual, realized benefits to customers.

Q. Is a financial incentive for the CVR program provided for under Michigan law?

A. Yes. Section 6x of 2016 PA 341 ("Act 341") and Section 75 of 2016 PA 342 ("Act 342") describe the financial incentive structure for energy waste reduction resources, including energy waste reduction, conservation, demand reduction, and other waste reduction measures. And Section 6a(13) of Act 341 gives the Commission authority to approve an alternative financial incentive structure if it determines that the defined structure would disfavor waste reduction measures when compared to utility supply-side investments.

Q. Do these measurable CVR efficiencies result in the Company making increased capital investments in other parts of the business?

A. No. While it is possible the Company could make other capital investments in addition to promoting system efficiencies, the Company makes investment decisions based on clear system needs, including safety, reliability, and affordability. The Company's proposed CVR financial incentive is designed to encourage utilities to look for new, innovative solutions and benefits that may not otherwise be explored. The traditional earnings model does not reflect the true value of these types of solutions – incentive mechanisms, including the proposed shared savings mechanism, bridge this gap and advance the state's environmental and societal policy goals of clean energy at affordable costs to customers.

Q. Does the traditional utility earnings model encourage investment in CVR?

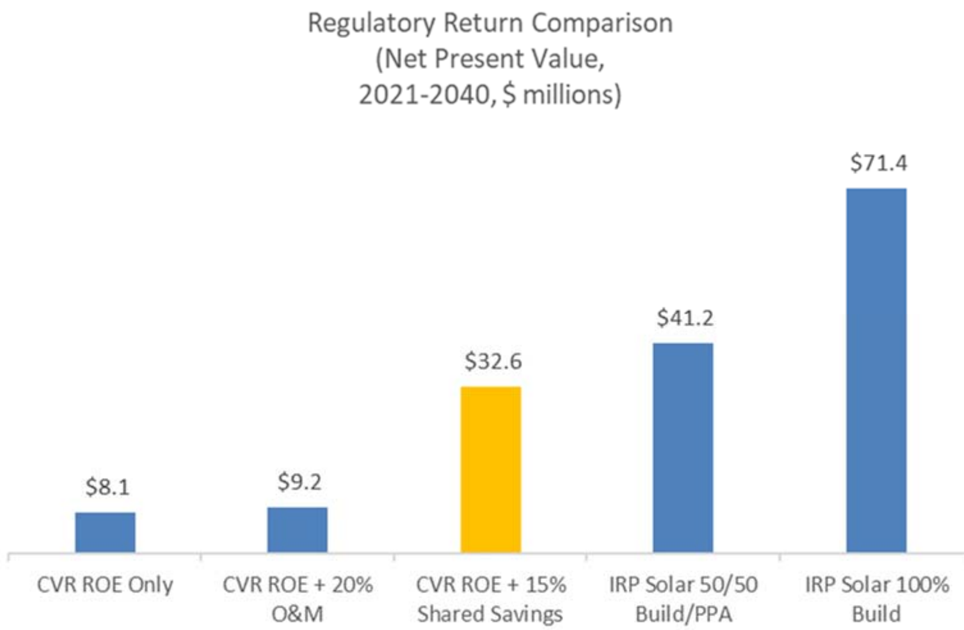
A. No. The traditional earnings model encourages capital investments that provide value to customers but does not encourage other investment approaches that may provide additional value. While CVR is a cost-effective program for customers, the associated capital investments are minimal. Because resource adequacy needs can be met through a supply-side resource, the Company could consider these more traditional prudent investments instead of CVR.

Q. Is a financial incentive necessary to place CVR on a level playing field with comparable, supply-side generation resources?

A. Yes. As demonstrated in the Company's IRP, the demand reduction and avoided capacity benefits achieved through the CVR Program replace the need for a traditional supply-side resource that utilities have historically relied on to provide affordable power to customers and a fair return to shareholders. When developing long-term resource plans, several factors are considered, including: cost, risk, portfolio diversity, the energy and capacity value the resource offers, and return on investment.

A shared savings financial incentive encourages the selection of CVR over a traditional supply-side resource such as a solar facility, as shown in Figure 1 below:

Figure 1



The primary earnings comparison in Figure 1 assumes additional solar would be procured under the terms of the settlement agreement in Case No. U-20165, with the Company owning 50% of the capacity and the remaining 50% purchased and subject to the Financial Compensation Mechanism.

Q. Why is the Company proposing a shared savings incentive for CVR as opposed to an approach like the Company's EWR or Demand Response incentive where the incentive is capped as a percentage of non-capital program spend?

A. An incentive based on program costs does not place CVR on a level playing field with a supply-side resource and does not promote CVR enhancements. Based on the CVR Program costs, utilizing the same incentive design as EWR would provide a financial incentive of approximately $80,000 in 2025 (Exhibit A-58 (MJD-1)). This minimal incentive does not reflect the value created by CVR, and the costs of administering the incentive program would likely exceed the incentive, particularly in the early years of CVR implementation.

A shared savings incentive approach allows the Company to share a small portion of the conservation and efficiency savings that would not have otherwise been created absent the CVR Program. As explained below (as well as in Company witness Blumenstock's direct testimony), CVR savings can be measured in a straight-forward manner. The Company is only able to recover an incentive if customer savings can be verified.

Q. Why is the Company proposing that the shared savings incentive be set at 15%?

A. A 15% shared savings incentive will help make CVR more comparable to a supply-side resource while also providing the majority of CVR savings to customers. While a 15% shared savings incentive and the Company's return for CVR capital investments does not create as much earnings for the Company as a 50/50 solar supply-side alternative, it does create a more comparable playing field. The proposed shared savings incentive encourages utility investments in CVR (and ultimately, less-capital intensive resources) and ensures customers will realize significant benefits from CVR implementation.

Specifically, the projected net present value of utility earnings from CVR from 2021 through 2040 with a 15% shared savings incentive is $ 32.6 million, compared to the net present value return of $41.2 million from the 50/50 solar supply-side alternative.

Q. Will the Company receive an incentive, regardless of actual program performance?

A. No. Under the shared savings proposal, the Company is not guaranteed an incentive. The Company would only be eligible for a shared savings incentive if it can demonstrate that the CVR Program investments have resulted in capacity and energy savings.

Q. What does the Company project its shared savings incentive to be in 2021?

A. Under the Company's proposed 15% shared savings mechanism, the 2021 incentive would be approximately $800,000. The Company's proposed incentive incrementally grows over time as the CVR Program is fully deployed and customers realize more savings. The structure of the Company's proposal allows the Commission to evaluate the success of the program while the incentive is still relatively modest.

Q. How are customer savings calculated and measured?

A. Customer savings will be calculated by recording the measurements captured at the substation with Supervisory Control and Data Acquisition ("SCADA"). Savings will be calculated by comparing the measurements captured at the SCADA substation to those measurements captured at the AMI meter or service point. Company witness Blumenstock provides additional context on how CVR is deployed and utilized in the distribution system.

Q. How is the Company proposing to recover the shared savings incentive?

A. The Company proposes to recover the CVR incentive through a surcharge mechanism explained by Company witness Heidi J. Myers. The estimated incentive, as shown in Exhibit A-58 (MJD-1), line 24, will be collected through the surcharge mechanism beginning in 2021, and later reconciled based on actual savings that customers receive.

<u>Long-term benefits of a CVR incentive for customers and the State of Michigan</u>

Q. How does an incentive mechanism for CVR create opportunities for innovation?

A. An incentive mechanism encourages utility programs that provide significant value to customers. An incentive mechanism connects broader customer and societal values with shareholder value creation. It is good policy to support shareholders receiving value from programs that advance environmental, affordability, and efficiency objectives.

This approach to value creation aligns with how other publicly-traded businesses operate in non-utility industries. Businesses naturally focus their discretionary resources and are willing to take risks in efforts that have the greatest potential rewards. As described above, the traditional regulatory model significantly disfavors utility efforts in CVR when compared to investments in a reasonable supply-side alternative. The proposed shared savings incentive encourages utilities to pursue new technologies, programs, and system designs that have the potential to create significant customer, environmental, and societal value.

Q. What impact does an incentive have on the pace of innovation?

A. Approving the CVR incentive will send a strong signal to utilities that they will be encouraged to pursue innovation that enhances utility customer value. This is expected to in turn promote increased utility focus and use of internal resources on programs that introduce new benefits to customers and promote affordability. It will encourage Michigan utilities to consider new approaches and help to place Michigan at the forefront of utility innovation.

Utility innovation is a vehicle to advance the State's societal and environmental policy. Promoting utility research and development of new energy solutions and technologies supplements the traditional capital earnings model to the benefit of customers. The regulatory process should not be viewed as a zero-sum game. By creating financial incentives for achieving and advancing shared interests in clean and affordable energy, the utilities will have the opportunity to create programs and processes that might never develop through the traditional utility regulatory approach.

As the Commission's approach to energy efficiency has demonstrated, strategically using financial incentives to encourage investments in resources with limited capital costs effectively delivers meaningful customer benefits, while rewarding utilities for developing cost-reduction programs.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697

DIRECT TESTIMONY

OF

DOUGLAS E. DETTERMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Douglas E. Detterman, and my business address is 1945 West Parnall Rd, 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 Executive Director of the Operational and Financial Planning Department.

Q. Please describe your educational background and work experience.

A. I graduated in 1990 from The Ohio State University with a Bachelor of Science in Mechanical Engineering. In 2004 I graduated from the University of Michigan with a Master of Business Administration. I joined CMS Energy Company in 2005 as a financial analyst, and I have subsequently served in various financial and operational roles within the Company.

Q. What are your responsibilities as Executive Director of the Operational and Financial Planning Department?

A. My responsibilities as Executive Director of the Operational and Financial Planning Department are to provide leadership as well as strategic and operational oversight of maintenance and construction work planning, scheduling, dispatch, contracting and close-out for the Company's electric and gas distribution operations.

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

A. The purpose of my direct testimony is to provide support for Consumers Energy's request for rate recovery for costs of its proposed capital investments and commensurate Operating and Maintenance spending in Low Voltage Distribution ("LVD") and High Voltage

Distribution ("HVD") at target levels inasmuch that significant maintenance and construction, engineering and ancillary resources are required.

First, I will discuss Consumers Energy's overall resource needs. Second, I will discuss the Company's resourcing approach, including the importance of leveraging both Company and contracted resources.

Q. Please summarize your conclusions.

A. My conclusions include the following: First, the Company, inclusive of its union and contract workforces, has demonstrated the ability to effectively and efficiently scale up its workforce capacity to meet its plans as demonstrated in 2019. Second, direct hiring and apprentice programs play a key and sustainable part in the Company's approach to secure resources and must be commensurately scaled and funded. Third, a robust and stable plan is an asset to attract and retain both internal and contract workers.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

I. OVERVIEW OF RESOURCE NEEDS

II. RESOURCING APPROACH

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-60 (DED-1) Electric Distribution Field Maintenance and Construction Resource Needs

Q. Was this exhibit prepared by you or under your direction or supervision?

A. Yes.

I. OVERVIEW OF RESOURCE NEEDS

Q. What are the resource needs to complete the capital investment plan as described by Company witness Richard T. Blumenstock's testimony and as summarized in Exhibit A-12 (RTB-1)?

A. The projected resources needs to complete the capital investment plan as described by Company witness Blumenstock and as summarized in Exhibit A-12 (RTB-1) are as shown in Exhibit A-60 (DED-1). In summary:

- LVD Field Maintenance and Construction resources are projected to increase by 18% versus the historical year; and

- HVD Field Maintenance and Construction resources are projected to increase by 45% versus the historical year.

Q. Are there other resource needs?

A. Yes. Engineering, Fleet, and Ancillary Resources will be discussed in Resourcing Approach.

II. RESOURCING APPROACH

Q. What is the Company's approach to meeting its resource needs.

A. The Company has been taking proactive measures to significantly increase its capability to execute the Electric Distribution and Infrastructure Improvement Plan including direct hiring and apprenticeships as well as building and expanding its contractor networks each with an emphasis on building scalable and effective local workforces.

A. LVD Maintenance and Construction

Q. How many LVD workers does the Company currently utilize?

A. Currently, the Company utilizes approximately 720 full time Consumers Energy employees to complete LVD maintenance and construction. In addition, the Company has divided the state into four zones with contracts competitively bid and awarded to provide support for each zone. Furthermore, the four zone contractors and numerous additional contractors may participate in specific bids for general service restoration support, as well as for specific project work. Typically, 50 to 80 three-person contract LVD crews may be engaged on the Company's system during normal "blue sky" conditions.

Q. How is the Company building the LVD workforce to complete the plan?

A. The Company is direct hiring skilled LVD workers, as well as leveraging apprenticeship programs with community colleges and the Utility Workers Union of America ("UWUA"). Moreover, the Company is partnering with the UWUA and contractors to further build specific underground LVD work-force capabilities and capacity needed to replace/install/maintain underground electrical lines and equipment.

B. <u>HVD Maintenance and Construction</u>

Q. How many HVD workers does the Company currently utilize?

A. Currently, the Company utilizes approximately 175 full-time Consumers Energy employees to complete HVD maintenance and construction. The Company has competitively bid and awarded contracts to provide primary HVD support for the state. In addition, the primary HVD contractor and numerous additional contractors may participate in specific bids specific for HVD project work. Typically, 25 to 40 three or four-person contract HVD crews may be engaged on the Company's system during normal "blue sky" conditions.

Q. How is the Company building the HVD workforce to complete the plan?

A. The Company works closely with its primary HVD contractor to ensure awareness and visibility into the plan as to ensure cost effectiveness, stability, and growth of the HVD workforce as needed to support the plan. Furthermore, the Company continues to competively bid and award specific project work to existing and new HVD contractors. The Company is also partnering with the UWUA to hire and train additional HVD workers to support the maintenance and operation of its HVD system including substations.

Q. Can you please describe Engineering, Fleet, and Ancillary Resources?

A. Engineering Resources are Consumers Energy and contract technical personnel needed to engineer and design projects. Fleet Resources consists of vehicles, machinery and equipment needed for Consumers Energy employees to perform their job duties such as setting a pole, stringing an above-ground line, and/or boring in an underground line. Fleet Resources also includes personnel to procure and maintain the vehicles, machinery, and equipment. Company witness Kyle P. Jones will discuss Fleet Resources in detail. Ancillary Resources are Consumers Energy and or contract personnel and supporting tools and equipment such as Property and Real Estate specialists, technical trainers and others who are essential to engineering, designing and completing projects. The Company uses a baseline staff of Consumers Energy personnel. Based upon workload and needs of service, incremental staff augmentation personnel are secured under contract on a temporary as needed basis from various vendors.

Q. Does this complete your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

KAREN M. GASTON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Karen M. Gaston, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am the Director of Corporate Budget, Planning and Analysis for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. How long have you been employed by Consumers Energy?

A. I have been employed by Consumers Energy since 2003.

Q. Please state your educational background.

A. I graduated from Grand Valley State University with a Bachelor of Business Administration with majors in accounting and finance. I also graduated from Spring Arbor University with a Master of Business Administration.

Q. What are your responsibilities in your current position?

A. As Director of Corporate Budget, Planning and Analysis, I am responsible for development of the financial plans, budgets, outlooks, forecasts, and analysis for corporate departments at Consumers Energy.

Q. Please describe your prior work experience.

A. I have held my current position since February 2018. Prior to this role, I held various manager, lead, and accounting analyst roles within the finance organization, including in the Accounts Payable, Payroll, General Accounting, and Property Accounting departments. In these roles, I have been responsible for processing vendor and employee payroll payments, expense reporting and tax filing and remittance, property records and depreciation analysis, financial results including accounting entry, and reporting and analysis, including Federal Energy Regulatory Commission ("FERC") and Michigan Public Service Commission ("MPSC" or the "Commission") report filings. From 2005 to 2008, I was a General Accountant for CMS Enterprises, responsible for accounting and financial reporting and analysis of subsidiary companies.

Q. Have you previously testified before the Commission?

A. Yes. I testified in Case No. U-20650, which is the Company's most recent gas general rate case.

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

A. My direct testimony is in two parts. In Part 1, I am presenting testimony supporting the test year Operation and Maintenance ("O&M") expense for Corporate Services, including uncollectible expense, and injuries and damages. In Part 2, I am presenting testimony supporting the test year capital expense for Corporate Services.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-61 (KMG-1)	Summary of Projected Electric & Common O&M Expenses for the Years 2018, 2019, 2020; and the 12 Months Ending December 31, 2021;
Exhibit A-62 (KMG-2)	Adjusted Electric Corporate Services O&M Expense for the Years 2018, 2019, 2020; and the 12 Months Ending December 31, 2021;
Exhibit A-63 (KMG-3)	S&P Global Market Intelligence ranking of Consumers Energy Electric A&G Costs for 2018;

Exhibit A-64 (KMG-4)		Electric Uncollectible Accounts Expense for the Years 2018, 2019, 2020; and the 12 Months Ending December 31, 2021;
Exhibit A-65 (KMG-5)		Electric Injuries & Damages Expense for the Years 2014 through the 12 Months Ending December 31, 2021; and
Exhibit A-12 (KMG-6)	Schedule B-5.4	Summary of Electric Corporate Services Capital Expenditures for the Years 2018, 2019, 2020; and the 12 Months Ending December 31, 2021.

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

A. Yes, they were.

PART 1 – ELECTRIC CORPORATE SERVICES O&M EXPENSE

Q. Please describe Exhibit A-61 (KMG-1).

A. Exhibit A-61 (KMG-1) summarizes the Company's total 2018 through the 12 months ending December 31, 2021 electric O&M expenses for Corporate Services, uncollectibles, and injuries and damages. Column (a) of this exhibit provides the O&M expense category; column (b) provides the source reference; column (c) provides the 2018 actual O&M expense; column (d) provides the projected 2019 O&M expense; column (e) provides the projected 2020 O&M expense; and column (f) provides the projected test year 2021 O&M expense. These expense categories are discussed in detail below.

Corporate Services O&M Expense

Q. What areas are included within the Corporate Services O&M expense category, as shown Exhibit A-61 (KMG-1), line 1?

A. Corporate Services includes those areas common to the administrative functions of a regulated corporation. These include Governmental, Regulatory, and Public Affairs; General Counsel, Legal, and Risk Management; Human Resources and Learning and Development; Transformation and Operations Support; Chief Financial Officer; Strategy; General Activities; and administration and other costs.

Q. Please provide a brief overview of the various areas within the Corporate Services area.

A. The areas within Corporate Services include:

- Governmental, Regulatory, and Public Affairs – This area acts as a conduit between the Company and its employees, customers, and external stakeholders. The group manages storm communications, promotes safety messaging, and advances clean energy programs for the benefit of customers via public media relations and inquiries, advertising, corporate news releases, social media management, and trade association dues and memberships. This area also manages regulatory commission expenses, foundation operations, and community programs. It is responsible for determination and management of regulatory filings, and management of the interface between the Company and regulatory staffs;

- General Counsel, Legal, and Risk Management – This area includes the Legal Organization, the Corporate Compliance Department, the Corporate Secretary Department, the Securities Law Group, Corporate Information Governance, and Risk Management. 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, and shareholder services. 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;

- Human Resources and Learning and Development (recently reorganized and renamed as People and Culture) – 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 our 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, performance management, workforce relations, employee engagement, and benefits administration. Also included is compliance assurance, which addresses legal and regulatory requirements such as Equal Employment Opportunity, Americans with Disabilities Act, and Family and Medical Leave Act;

- Transformation and Operations Support – This area includes corporate safety and emergency management, security administration, quality, and corporate employee travel services;

- Chief Financial Officer – This area provides the preparation of utility strategic plans, budgets, forecasts, and specialized financial studies. This area also includes the preparation and control of accounting records, including financial statements and reports, and the administration of accounting systems. These systems include budgeting and management reporting, general ledger, accounts payable, payroll, fixed assets, customer billing, payment processing, and financial and regulatory reporting. In addition, the internal audit functions (appraisal of business unit effectiveness of financial controls) and the internal control functions are conducted in this area. The corporate tax function includes all aspects of compliance with federal, state, and local income, sales and use, property, franchise, and excise taxes, book accounting for taxes, tax planning of transactions, tax research, the analysis of tax legislation and regulations, the management and negotiation of tax audits, and tax litigation. Treasury includes all aspects of Company financing and cash management, negotiation of Company credit facilities, treasury operations including initiating cash wire transfer transactions, processing checks for deposit, maintenance of all bank account related activities, borrowing, and investing. In addition, investor relations, rating agency, and investor support are included in the Chief Financial Officer area;

- Strategy – This area is responsible for performing analysis to generate recommendations that shape the Company's overall strategic direction. The Strategy organization manages the Company's long-term strategic planning process. Piloting of emerging technologies and customer offerings is also performed in the group;

- General Activities – These costs are an aggregation of expenses and credits that are not attributable to any one department but are incurred on behalf of the Company as a whole. Examples include capitalized credits to O&M, billing credits for administrative and general ("A&G") labor, expenses, and outside services as part of a full-cost loading adder, senior management time and expenses, and Board of Director costs; and

- Administrative and Other – These costs are primarily for Edison Electric Institute dues, environmental minimum liability accruals, and intervenor funding for the power supply cost recovery cases.

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, benefits are allocated based on either employee counts or labor, general costs are allocated based on the Three Factor Allocation Method, with other costs being directly charged for identified activities, allocated based on capital and O&M spending levels 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 gas businesses.

Q. Please explain how the Adjusted Corporate Services' O&M expense was calculated.

A. Exhibit A-62 (KMG-2), line 13, provides the Company's electric portion of total Corporate Services expenses, before adjustments. The 2018 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-62 (KMG-2), line 20, column (d), shows the total normalizations of one-time costs from 2018 total Corporate Services expense. The normalization found on Exhibit A-62 (KMG-2), line 20, relates to a reduction of storm insurance costs due to foregoing the renewal of the Company's storm insurance policy. Also, the total of items disallowed by Commission order related to advertising, lobbying, and donation payments were removed on Exhibit A-62 (KMG-2), line 22. Total adjusted Corporate Services expense is found on line 23. Corporate Services labor is escalated using an assumed 3.2% merit rate. Headcount is projected to remain at 2018 levels through the test year. The use of contract labor in the Corporate area is de minimis. Consumers Energy uses the inflation rate to project non-labor Corporate Services O&M and seeks to limit non-labor Corporate Services O&M increases to the rate of inflation.

Q. What is the projected rate of non-labor inflation?

A. The assumed rate of non-labor inflation is based on the Consumer Price Index. The Consumer Price Index is 2.0% for 2019, 1.5% for 2020, and 2.3% for 2021.

Q. What is the source for the Consumer Price Index?

A. The November 2019 IHS Markit forecast.

Q. In addition to increases related to inflation, are specific line item changes included to arrive at the test year O&M expense projection?

A. Yes. Significant insurance refunds and credits for Nuclear Electric Insurance Limited, Energy Insurance Mutual, and Factory Mutual were projected using actual refunds and credits received from 2014 through 2018. Due to loss experience and the volatility in investment markets, Consumers Energy has not consistently received annual refunds or credits from these companies. For these reasons, as well as the uncertainty around the impact of future claims, the future receipt of these refunds and credits are difficult to project. Accordingly, a five-year averaging approach provides a reasonable estimate of these refunds and credits for the projected test year. Below is a table showing the 2014 through 2018 historical amounts and the five-year average included in the projected test year.

Insurance Refunds/ Credits	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	5-Year Average
NEIL	2,176,509	2,205,189	2,213,763	2,184,827	9,382,171	3,632,492
EIM	307,447	300,416	299,241	364,041	907,623	435,754
FM	853,569	849,722	875,314	855,487	562,645	799,347
Total	3,337,525	3,355,327	3,388,318	3,404,355	10,852,439	4,867,593

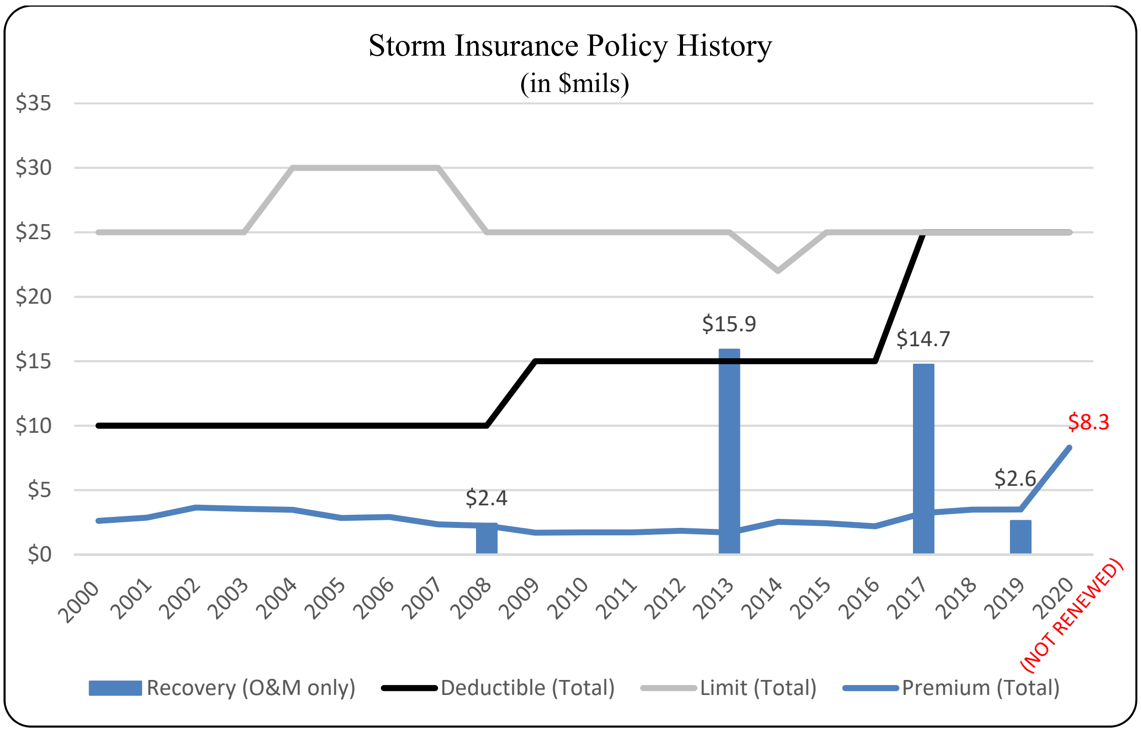
Q. What costs are normalized out to arrive at the test year O&M expense projection?

A. The cost for the 2018 storm insurance policy was normalized out of future projections because the insurance policy was not renewed in 2019.

Q. Why was the storm insurance policy not renewed?

A. The Company has historically carried storm insurance as a means to limit liability from service restoration costs when catastrophic storms occur. Annually, a review of the terms, coverage, and costs of the policy is performed to evaluate the economic benefit of renewing the policy. Over time, the policy premium and deductible have both increased.

In October 2019, the cost to renew the policy was projected to be around $8.3 million, an increase of 137% compared to the prior policy premium of $3.5 million. The significant increase in the policy premium, coupled with the low number of historical occurrences when costs were recovered, made the policy terms uneconomic for customers, and therefore the storm insurance policy was not renewed. Below is a chart depicting the trends of storm insurance policy deductibles, policy limits, premiums, and recoverable costs over time.



Q. How will the Company recover service restoration costs in the future without storm insurance coverage?

A. The Company proposes that it is more economic for customers if the Company "self-insures" via deferred accounting treatment for recovery of service restoration costs in excess of $10 million over the amount set in rates. The proposed deferred accounting treatment is described in the direct testimony of Company witness Daniel L. Harry.

Q. Why is this proposal for deferred accounting treatment of service restoration costs more economic for customers than storm insurance coverage?

A. With this proposal for deferred accounting treatment of service restoration costs, customers benefit in two ways: (1) elimination of the on-going storm insurance premium expense included in rates, which would have been $8.3 million of insurance premium expense to renew the policy in 2020; and (2) customers only pay for service restoration costs actually incurred. Hedging financial risk of catastrophic service restoration costs using insurance is only advantageous when recovery of storm costs exceeds the insurance premium plus the deductible paid, up to a limited threshold set by the insurance company. Historically, premiums have typically been higher than what has been recovered through insurance. Therefore, the Company did not renew the storm insurance policy and proposes deferred accounting treatment of service restoration costs in excess of $10 million over the amount set in rates as a more economic and advantageous way to cover service restoration costs for customers.

Q. Are the costs associated with restricted stock and the Employee Incentive Compensation Program ("EICP") included in the 2018 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 Company planning technology projects that support the Corporate Services functions?

A. Yes. Company witness Jeffrey D. Tolonen includes in his direct testimony and exhibits, a number of 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. These projects are described below:

- The **Accounts Payable ("AP") Automation** project requires $104,280 in O&M in the test year. The AP Automation project will provide an end-to-end AP solution to optimize invoice capture via Optimal Character Recognition ("OCR") software; leverage workflows to automate invoice approvals and processing; manage electronic document retention; provide insights via improved reporting; and minimize human intervention. The value of completing the project includes: (1) centralizing invoice processing resulting in reductions to invoice entry costs, number of paper invoices, duplicate vendor payments, and late vendor payments; (2) automating validation of an invoice against contract rates; (3) increasing transparency of invoice processing status; (4) providing more accurate accruals; (5) improving the ability to capture discounts; (6) enabling cash flow benefits and reduced financing costs; and (7) improving internal controls. The scope of the project includes: (1) enabling OCR technology; (2) creating automated workflows for receiving, managing, routing, and monitoring invoices and related documentation; (3) automating posting of invoices; (4) creating new reports; (5) enabling electronic document retention; and (6) data cleanup. Four alternatives were considered for the AP Automation project: (1) Continue current process using outline agreements without a third party tool. While this requires no capital investment, the Company continues to have duplicate payments, be ineligible to receive discounts, have inefficient processes, and lack end-to-end automation; (2) Develop a custom solution which would meet all requirements, but would result in higher overall costs, higher maintenance costs, fewer upgrades, and won't leverage AP best practices; (3) Choose an on-premise software tool resulting in cost savings and efficiencies related to processing, storing data in house, and implementing AP best practices. It would also introduce new licensing and ongoing maintenance costs; and (4) Choose a cloud solution resulting in reduced infrastructure costs, less internal maintenance than an on-premise solution, capability for vendors to access the system and see invoices, and implementing AP best practices. This solution would introduce new licensing and ongoing maintenance costs and upgrades would be forced upon the Company that require testing, which could impact and interrupt operations. The preferred options are (3) and (4) since these options will provide a solution which will deliver cost savings and reflects AP best practices. A final decision will be made after a Request for Proposal ("RFP") is issued and a vendor is selected.

- The **Enterprise Content Management ("ECM") - Managing Business Records** project requires $251,486 in capital and $486,420 in O&M in the test year. Using the Company's ECM system, this project will manage business records for high-focus areas contained in SharePoint and Shared Drives. The records will be classified, categorized, and placed under formal retention rules, via metadata assignment. This project will add value through: (1) consistent practices for records management; (2) defensible process for validating completeness and accuracy of records produced and records deleted; (3) deletion of excess, irrelevant, or inappropriate information; (4) easy generation of electronic records in the event of litigation; (5) achieving Generally Accepted Recordkeeping Principle maturity of 3.0 or greater through functional capabilities of ECM coupled with business practices to align to ARMA (formerly the Association of Records Managers and Administrators) principles; and (6) mitigating the possibility of fines as a result of being unable to produce records. For high-focus areas, the scope includes: (1) integrating SharePoint and Shared Drive content into ECM; (2) assigning taxonomy and records classification values through metadata on content and records; (3) assigning standard retention rules; (4) mapping, building routines, and migrating existing content to new taxonomy and retention schedules; (5) ensuring records can be located; and (6) allowing legal holds and lineage audits to be conducted on content. Three alternatives were considered for this project: (1) Continue managing business records on shared network drives and in SharePoint without ECM integration. This option was not chosen as it would provide minimal visibility to the records from within the ECM system, retention rules will not be applied to the records, taxonomy or metadata will not be applied making it more difficult to find and manage records, the problem will continue to get worse over time as the amount of data grows, and the Company could face substantial fines if it is unable to find records; (2) Integrate all SharePoint and shared drive content in the ECM. This option was not chosen as it will be costly and not all content is considered a business record; (3) Start by focusing on integrating business critical records with ECM for the high-focus areas. Alternative (3) was selected as it mitigates risk with the high-focus areas and requires less funding than managing all SharePoint and shared drive content in ECM.

- The **Environmental Health and Safety ("EHS") Compliance** project requires $63,601 in O&M in the test year. The EHS Compliance project will implement a comprehensive Company-wide solution to ensure accurate and consistent reporting of health, safety, environmental, and security issues and activities including: (1) compliance calendaring, (2) incident and risk management, (3) inspections, (4) waste management, and (5) sustainability. Completion of this project will provide value to both the Company and its customers by incorporating the improved processes built into the new solution, including incident management and prevention, that ensure a productive workforce able to complete work for customers. Additionally, the project will: (1) support the Company's "Planet" goal through enhanced tracking and reporting for air quality, waste management, and sustainability; (2) support risk avoidance for environmental penalties; (3) increase productivity and quality; (4) enable transparency in tracking of goals; and (5) create awareness of and improve response to emerging environmental regulations through the addition of visual management and dashboards. The scope of this project is to implement a cloud solution which includes installing and configuring: (1) incident investigation, incident risk assessment, and task management; (2) corrective action tracking, workflows, and reminders; (3) environmental waste management; (4) inspections; (5) compliance calendar; and (6) sustainability. The project also includes implementation of standard business processes for EHS incident management, near misses, and safety observations. Three alternatives were considered for this project: (1) continue with disparate Excel and SharePoint solutions, which was not selected because the Excel and SharePoint solutions would require lengthy manual efforts and include risk to accurate and central tracking of EHS data; (2) pursue separate projects for Environmental Compliance and for Safety and Health Compliance, which was not selected because formal Requests for Information revealed that industry standards for these solutions utilize integrated functionality for Environmental Compliance and Safety and Health Compliance; and (3) implement a single solution for both Environmental Compliance and Safety and Health Compliance. Alternative (3) was selected because it consolidates data in one system and requires less ongoing expense than two individual solutions would require. The selected alternative also considered both on-premise and cloud solutions. The single cloud-based solution was selected as the most efficient due to lower implementation and ongoing maintenance costs.

- The **Financial Planning Transformation - Intake and Monthly Plan Management** project requires $3,407,190 in capital and $287,100 in O&M in the test year. The Financial Planning Transformation – Intake and Monthly Plan Management project will improve portfolio management capabilities in financial planning processes (also referred to as integrated business planning). This project includes the design, development, and implementation of a performance based budgeting system that will automate the input of actual results, integrate planning and actual data with monthly forecasting to provide for robust cost modeling, and provide automated and flexible reporting. Benefits from this project include: (1) labor savings across the Company through automation of manual work processes for data entry, reconciliation, and reporting; (2) improved data quality through integration of the budget and actual data systems; (3) powerful and flexible reporting for in depth analysis; (4) enable "zero-based" budgeting with all organizations entering full time equivalents (FTEs), overtime, contractor, and other units of work to drive performance based decision making, and (5) serve customers' interest by making the capital and O&M budgeting process as transparent and efficient as possible. The entire set of benefits will provide a more efficient process for accessing and making this information available, such as in support of annual rate case filings. The project scope includes: (1) managing Work Intake (the submission of programs and projects within the financial planning process); (2) developing Intake Scenarios Prioritization and Workflow (the process through which all projects are reviewed then prioritized, creating different scenarios for management review and decision making, and implementing the workflow needed to take an idea from creation to inclusion in the financial plan); (3) connecting planning, prioritization, and decision making to

Company objectives and goals; (4) storing plans and scenarios for future reference of historical data; (5) bringing actuals and plan/forecast together for monthly review and forecast updates; (6) providing the ability to track and store risks and opportunities; and (7) bringing both financial and work volume (units) together for forecasting and planning to facilitate effective cost management practices like comparing the actual value of work performance to the budgeted cost of work planned. The three alternatives considered for this project were: (1) leverage and make changes to the Company's home-grown Business Planning System, which was not chosen due to technology limitations in the existing system, and use of a custom-developed program that does not offer the improved capabilities; (2) consider other third-party applications to provide the functionality; and (3) use the existing SAP system to provide the functionality, which provides the advantages of including existing integrations to forecasting and budgeting in SAP, directly connecting the planning system to the financial management system, using existing investments in SAP, and realizing benefits of updating processes and eliminating manual processes. The preferred options are (2) and (3) as they would integrate more seamlessly with the Company's existing Financial Modeling platform and technology and provide a more comprehensive end-to-end planning solution. A final decision will be made in 2020 for 2021 implementation after an RFP is issued and a vendor is selected.

- The **Human Resources - 2020 Union Changes** project requires $177,679 in O&M in the test year. The Human Resources - 2020 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. 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, 2020. The VCC agreement ends August 1, 2020. The Zeeland agreement ends October 1, 2020. 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, VCC, and Zeeland union employees. The scope of this project encompasses making any system changes required to support the new working agreement for the OM&C, VCC, and Zeeland employees. Exact details will be finalized after the negotiation process is completed and contracts are approved. Three alternatives were considered for this project: (1) Make no system changes after the contracts are ratified. This option was not chosen because it exposes the Company to possible fines, disengaged employees, union grievances, significant manual processes leading to greater possibility of error, hiring additional staff to perform activities outlined in the agreements, and increased legal costs due to employee grievances; (2) Find other third-party software to support the changes required by the union agreements. This option was not chosen because it would require SAP integration along with additional software licensing and maintenance costs; (3) Make system changes to eliminate manual updating, comply with the working agreement language, support union employee engagement, and reduce grievances was chosen because it uses current SAP technology, automates what would otherwise require manual processing, and is the least costly option.

- The **Rates Case Implementation** project requires $172,135 in O&M in the test year. The Rates Case Implementation project will modify SAP billing in accordance with MPSC requirements, allowing rate structure changes and improved billing accuracy. The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; and (2) timely updates to Company applications that incorporate mandatory changes to the rate structure that include new surcharges, price changes, and energy efficiency programs. The scope of this project encompasses implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC. An alternative considered for this effort was an offshore development model. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high because of the complexities of the rate structure, new development, and timing it would take for testing of this model.

- The **Rate Design and Evaluation Tool ("RDET")** project requires $545,698 in capital and $181,576 in O&M in the test year. The RDET project will provide the Company the ability to design, analyze, and evaluate proposed electric rates with automated tools. This will permit the Rates Team to quickly adjust to proposed electric rate changes and identify which customers would be impacted by a rate change. The Company and its customers will receive value through this project by: (1) streamlining processes for rate analysis and design; (2) automating data extraction and analysis; and (3) improving billing accuracy when new rates are implemented. The scope for the project includes: (1) implementing RDET; (2) deploying integrations to send relevant rate data to RDET; and (3) training staff on utilizing RDET. Alternatives considered include: (1) Implement an alternative vendor solution to support the rate analysis and design activities. This alternative was not selected as the product has higher project costs than the chosen solution and the Company is already engaging with the selected vendor for a separate effort. This alternative would also increase operational costs by introducing additional ongoing maintenance expenses; (2) Utilize the Company's internal Data Lake and Tableau. This alternative was not chosen as it is not cost effective to replicate the capabilities of the selected solution internally; and (3) Implement the selected vendor platform. The Company selected this option because of the minimal impact to operational expenses by leveraging a vendor platform already implemented at the Company. The selected solution will create synergies by aligning several internal organizations on a single platform for rate analysis and comparison. In addition, the selected solution is considered industry best in class.

- The **Workforce Connect – Talent Enablement** project requires $329,946 in capital and $1,412,714 in O&M in the test year. This project is part of an overarching talent enablement plan which will enable the Company to move forward in creating an employee experience to better serve customers. Improving the employee experience is focused on two outcomes: (1) enabling employees to be more engaged and productive; and (2) attracting and retaining new skill sets and talent, both of which result in providing better service to customers, an improved customer experience, and higher customer satisfaction. This project will provide the following value: (1) increased employee retention for continuity of knowledge and long-term customer relationships, as well as reduction in costs associated with recruiting and onboarding new employees; (2) positive direct customer interactions facilitated through strong employee engagement; (3) enhanced employee development to meet customer needs during a time where retirement eligibility is high and risk of knowledge loss has the potential to negatively impact customer service and satisfaction; (4) enable the Company to operationalize a new career framework and competency model which will support training and development of employees to deliver strong customer service and will enhance the ability to hire candidates capable of delivering on the Company's initiatives and goals; (5) advanced workforce analytics that provide data-driven insights in support of maintaining and enhancing the workforce to continue to deliver strong customer service and results; (6) reduce waste and defects leading to increased quality and simplified manual processes; (7) improved insight and consistency in reporting (i.e. Ethics, Safety, Office of Federal Contract Compliance Programs); (8) provide transparency into key talent areas to identify retention risk within critical areas and develop succession strategies; and (9) ensure core systems are stable and operational interruptions are minimized. The Company currently uses the SAP Human Capital Management ("HCM") module as a master source of employee data which feeds such information to other systems throughout the Company, including Human Resources and non-Human Resources systems. However, vendor support for the SAP HCM module will be retiring at the end of 2025. The Workforce Connect – Talent Enablement project will implement the following SAP SuccessFactors modules: Employee Central, Succession Planning, Career Development, and Compensation. This project will ensure support of the following processes after the SAP HCM module retires: Core Human Resources Management, Hiring, Onboarding, Performance Management, Succession Planning, Compensation and Benefits, Leader and Employee Development, Technical Training, Talent Programs, Workforce Analytics, and Workforce Planning. The project scope includes: (1) implementing SAP SuccessFactors Employee Central, Succession Planning, Career Development, and Compensation modules; (2) retrofitting current SuccessFactors modules to support the integrated talent management suite; (3) providing mobile capabilities; (4) retiring the SAP HCM module;

and (5) providing integrations as needed from SuccessFactors to SAP. Four alternatives were considered for this project: (1) Maintain employee master data in the SAP HCM system, knowing that vendor support for HCM will be retiring at the end of 2025. This approach was not chosen as it poses a risk to system stability due to declining vendor support (such as maintenance, enhancements, and defect resolution) which could have Company-wide implications given the extent to which SAP HCM integrates with other systems throughout the Company and the number of functions and processes reliant on employee data; (2) Explore alternate systems instead of SAP HCM for core Human Resources data and transactions. Consumers Energy uses 15 SAP modules, which are reliant on employee data from SAP HCM. Additionally, more than 40 other systems and applications are integrated with and dependent on the SAP HCM data. Migrating to a non-SAP Human Resources system would result in customization of technical integrations back to SAP and other systems currently integrated with SAP HCM. This approach was not selected, as migrating to a non-SAP core Human Resources system would incur significant re-work costs and would have Company-wide implications. For example, Company employees would need to be retrained and new technology support contracts would need to be negotiated at a higher cost; (3) Replace the SuccessFactors solution with another talent management system. This option was not chosen since it would be costly to start over with a brand new talent management system, would result in significant organizational change management to support user adoption and loss of significant time and training invested in skilling up employees to use and maintain SuccessFactors, and would require retraining of the Human Resources Technology team as well as the majority of Human Resources employees who regularly use the current system in their day-to-day work; and (4) Expand the current Workforce Connect (SuccessFactors) solution with SAP's Employee Central product and configure additional SuccessFactors modules. This option is preferred as it minimizes impact and customization to other existing Company-wide technical solutions and processes dependent on employee data and mitigates the risk of relying on the retiring SAP HCM system. Implementing SAP SuccessFactors Employee Central will enable standard, non-custom integration with on-premise SAP modules as well as seamless integration with current Workforce Connect (SuccessFactors) modules. Additionally, enhancing current modules and implementing the remaining SuccessFactors modules supports the overarching talent enablement plan.

Q. Is the Company planning projects that support the Corporate Services functions?

A. Yes. The Company is planning a talent enablement project that is critically important in allowing the Company's Human Resources area to support the Electric business in a safe, effective, and efficient manner. The talent enablement project is part of an overarching, multi-year talent enablement plan that includes both technology and non-technology efforts. The technology project associated with the talent enablement plan is described above in the technology projects section. The non-technology projects associated with the talent enablement plan are described below:

- The **Career and Reward Framework** project will utilize an industry expert to develop and implement a framework that creates clear career paths and career development opportunities for employees, while engaging in market-based compensation practices to attract, reward, and retain the talent needed to deliver on the Company's initiatives in the evolving utility industry. For example, as energy generation, distribution, and storage transforms, the Company will need a workforce skilled in renewable generation. As technology becomes more integrated, the Company will need enhanced and evolving cyber security skills to protect the grid. As customer expectations shift to desire on-demand expert advisement and a more personalized experience, the Company will need a workforce skilled in employing the power of data to meet customer needs. A variety of new skills will be needed to support this transformation, and the Career and Reward Framework project will provide a structure for the Company to continue to build these skill sets, including upskilling current employees and hiring new employees with different talents. The knowledge, skills, and abilities of employees are key determinants in the quality and timeliness of service that customers receive. The ability to deliver what customers expect – such as reliable and safe energy delivery, on-time completion of service orders, energy savings, accurate billing, and easy-to-navigate website and mobile applications – depends upon having the right talent, in the right job, at the right time. Customers benefit when the Company can attract the best people and retain their consistent expertise and growing experience for a long time. Reducing employee turnover also saves the expense and lost productivity associated with frequent recruiting and training.

- The **Leadership Development** project, also referred to as Leader College, will expand the current leadership training program to meet the changing needs of leadership capabilities in the utility industry to provide improved employee and customer experiences. This project entails the development, implementation, and delivery of an enhanced leadership training program. Leader College will deliver a tailored curriculum of organizational learning programs designed to develop capabilities and qualifications necessary for leaders to manage effective teams and foster an inclusive and diverse culture, while making decisions aligned with the Company's goals to deliver customer value. The curriculum will be tailored based on a leader's development needs and includes: (1) tools and training to attract and retain the best candidates whose skills fit their positions; (2) coaching for developing and career planning of employees; and (3) practical application in the business setting. The benefits of an enhanced and tailored leadership development curriculum include a streamlined plan for upskilling leaders in key areas needed to best serve their teams and customers, lower recruitment and turnover costs, and knowledgeable, engaged, and productive teams that are motivated to deliver first-time quality and on-time service to customers.

Q. How do the talent enablement projects benefit customers?

A. Consumers Energy has set out to build on its strong workplace culture and training programs by implementing a new career and reward framework and enhanced leader development program for employees. A career framework helps employees define their role, expand their skill set, and develop their career consistent with the Company's initiatives. A reward framework supports efforts to continue to compensate employees fairly and competitively. A leadership development training program and enhanced and tailored leadership development curriculum provide a streamlined plan for upskilling leaders in key areas needed to best serve their teams and customers, lower recruitment and turnover costs, and knowledgeable, engaged, and productive teams that are motivated to deliver first-time quality and on-time service to customers. Customers benefit from these programs through increased employee retention for continuity of knowledge and long-term customer relationships, reduction in costs associated with recruiting and onboarding new employees, positive customer interactions facilitated through strong employee engagement, and enhanced employee development to meet customer needs.

Q. Is the level of test year Corporate Services O&M expense reasonable?

A. Yes. The reasonableness of the O&M expense levels is supported by the fact that S&P Global Market Intelligence ranked Consumers Energy's 2018 electric A&G costs (excluding pension and benefits) the sixth lowest out of 34 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 great indicator of the Company's diligence in managing overhead costs to help keep rates affordable for customers. Please refer to Exhibit A-63 (KMG-3) for a 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.

<u>Electric Uncollectible Expense</u>

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 $18.1 million, as shown on Exhibit A-64 (KMG-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 2016 through 2018, as shown on Exhibit A-64 (KMG-4), page 2. This ratio is applied to the test year electric service revenue, plus Energy Waste Reduction surcharge revenue, to arrive at the sub-total of uncollectible accounts expense on Exhibit A-64 (KMG-4), page 2, line 10, column (e).

Q. Does the estimate of uncollectible accounts expense consider changing fuel and power costs, their impact on customer bills, and the corresponding impact on uncollectible accounts expense?

A. Yes. By using the test year revenues times the three-year average BDLR, the latest fuel and power cost projections are taken into account.

Q. Does this method provide a reasonable estimate of uncollectible expense?

A. Yes. The Company continuously strives to reduce uncollectible accounts expenses. However, year-over-year, uncollectible accounts expense can be impacted by many factors. The economy, the effectiveness of collection practices, funding of low-income assistance programs, extreme weather fluctuations, or any number of other factors that could impact a customer's ability to pay. As a result, the Company has consistently used a three-year average BDLR approach in its recent rate case filings. This method most effectively captures the recent trends of the many factors that can impact uncollectible accounts expenses. This approach was used in the Company's most recent electric rate case in Case No. U-20134.

Q. What mitigation strategies has the Company used to manage uncollectible expense?

A. Over the last several years, the Company has implemented several mitigation strategies serving to reduce uncollectible expense. First, turn on compliance was implemented to stop the cycle of carrying a past due balance to a newly opened account. Processes were put in place that required customers with an unpaid balance to pay the old balance in full, prior to opening a new utility account. Second, the Company prioritized collection activities on high risk and high volume past due accounts to reduce the overall company arrears balance. In addition, the implementation of smart meters has helped to reduce uncollectible expense through automated turn-off capability. The benefits of these actions are reflected in the continuous decline in net write-offs from 2014 through 2018.

Electric Injuries and Damages Expense

Q. Please describe Exhibit A-65 (KMG-5).

A. Exhibit A-65 (KMG-5) summarizes the Company's total 2014 through 2018 actual electric injuries and damages expense and projected injuries and damages expenses through the 12 months ending December 31, 2021.

Q. Please describe the costs related to injuries and damages.

A. Electric injuries and damages include liabilities that arise in the normal course of Company business for various types of items such as compensation for damaged trees and crops; restoration of driveways, lawns, and fences; and accidents and lawsuits (up to a $500,000 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 $4.5 million be included for the test year as shown on Exhibit A-65 (KMG-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-65 (KMG-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 2014 through 2018.

PART 2 – ELECTRIC CORPORATE SERVICES CAPITAL EXPENDITURE

Q. Please describe Exhibit A-12 (KMG-6), Schedule B-5.4.

A. Exhibit A-12 (KMG-6), Schedule B-5.4, summarizes the Company's total 2018 through the 12 months ending December 31, 2021 electric capital expenditures for Corporate Services. Column (a) of this exhibit provides the capital expenditure category; column (b) provides the 2018 actual capital; column (c) provides the projected 2019 capital; column (d) provides the projected 2020 capital; column (e) provides the projected 24 months ending December 31, 2020 capital; and column (f) provides the projected test year 2021 capital. These categories include costs to equip and support Corporate Services areas primarily at Company headquarter locations with office furniture and equipment.

Q. How did the Company determine the Corporate Services' capital expenditures included in the test year?

A. The Company projects the electric portion of Corporate Services capital for the test year at $472,000, as shown on Exhibit A-12 (KMG-6), Schedule B-5.4, page 1, column (f). The projected test year Corporate Services capital is based on 2019 planned purchases and activities, with an inflation rate added to project non-labor Corporate Services capital for 2020 and 2021.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief. ______________________________________	))))))	Case No. U-20697

DIRECT TESTIMONY

OF

DANIEL L. HARRY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Daniel L. Harry, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am the Director of General Accounting for Consumers Energy Company ("Consumers Energy" or the "Company").

Q. How long have you been employed by Consumers Energy?

A. I have been employed by Consumers Energy since 1999.

Q. Please state your educational background.

A. I graduated from Central Michigan University with a Bachelor of Science in Business Administration with a major in accounting.

Q. What other professional designations do you hold?

A. I am a Certified Public Accountant registered in Michigan.

Q. What are your responsibilities in your current position?

A. As Director of General Accounting, I am responsible for the financial statement preparation and analysis for Consumers Energy and supporting various Company regulatory and external reporting requirements.

Q. Please describe your prior work experience.

A. I have held my current position since February 2018. From 2014 to February 2018, I was Director of Accounting Process and Control, responsible for the ongoing financial analysis of utility operations, with a focus on accounting process and control. From 2008 to 2014, I was the Director of Business Support – Rates for Consumers Energy, responsible for the development of the gas utility strategic plans, budgets, outlooks, and forecasts as well as the ongoing financial analysis of gas utility operations. In that capacity, I was also responsible for the development of the electric and gas deliveries and revenue forecasts. From 2003 to 2008, I was the Director of Accounting Research for Consumers Energy, responsible for implementation of new accounting standards and for determining the appropriate accounting for major transactions. From 2001 to 2003, I was a Senior Accountant, responsible for electric revenue and power cost accounting. From 1999 to 2001, I was a General Accountant, responsible for external reporting, accounting research, and subsidiary accounting.

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

A. Yes, I have testified before the Commission on a number of occasions. Specifically, I have testified in Case Nos. U-15986, U-16418, U-16855, U-17197, U-17735, U-17643, U-17882, U-17990, U-18124, U-18322, U-18424, U-20134, and U-20322.

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

A. I am presenting testimony requesting accounting approval for the use of regulatory assets or regulatory liabilities, as needed, if the following proposals are approved:

1. the Deferred Capital Spending Recovery Mechanism;
2. deferral of the Karn 1 and 2 Retention and Separation Costs;
3. the PowerMIFleet Electric Vehicle ("EV") Charging Deferred Accounting Proposal;
4. the Conservation Voltage Reduction ("CVR") Incentive Proposal;
5. the Deferred Service Restoration Proposal; and
6. the Financial Compensation Mechanism ("FCM").

I am also providing the basis for the two-year collection requirements under Generally Accepted Accounting Principles ("GAAP") for the recognition of the Financial Compensation Mechanism, the Demand Response Incentive, and the Conservation Voltage Reduction Incentive. In addition, I am providing an explanation of why investments in cloud-based technologies require an alternative projected working capital approach for rate-making purposes. Finally, I am requesting approval to follow Federal Energy Regulatory Commission ("FERC") accounting guidance released December 20, 2019 in Docket No. AI20-1-000, *Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract.*

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-66 (DLH-1)	Amortization of Karn Plant Retention and Separation Costs for the 12-Months Ended December 31, 2021

Q. Was this exhibit prepared by you or under your direction or supervision?

A. Yes.

<u>Deferred Capital Spending Recovery Mechanism</u>

Q. Please state the proposal for a deferred capital spending recovery mechanism.

A. The Company requests that the Commission authorize Consumers Energy to utilize deferred accounting associated with actual capital spending in the event the Commission's final order in this proceeding sets capital spending levels for recovery in rates at amounts below the amount requested for the 2021 test year in the following programs in Company witness Richard T. Blumenstock's direct testimony:

- distribution new business;
- distribution demand failures; and

- distribution asset relocation capital program.

Deferrals for each program during the test year would be based on capital spending above amounts approved in rates.

Q. Please describe how the deferred capital spending recovery mechanism would work?

A. The deferred accounting would be limited to the return on, return of, and property taxes associated with the actual capital spending above the approved amounts (including carrying costs). The impact on return on, return of, property taxes, and carrying costs as a result of spending above the threshold amounts will be recorded in a regulatory asset until the associated capital assets are included in rate base in the Company's next electric rate case.

Q. Does the implementation of a deferred capital spending recovery mechanism require any specific accounting approvals?

A. Yes. The deferred capital spending recovery mechanism would result in deferred debits until the expense components in the mechanism can be fully collected. The Company requests approval to recognize regulatory assets, as needed, to record these deferred amounts.

Q. Would any outstanding regulatory asset associated with the deferred capital spending recovery mechanism accrue interest?

A. Yes. Any outstanding regulatory asset associated with this mechanism would accrue interest at the Company's short-term borrowing rate.

Karn 1 and 2 Retention and Separation Costs

Q. Please state the proposal for recovery of costs related to the Karn 1 and 2 retention and separation plan.

A. The Karn 1 and 2 retention and separation plan is supported by Company witness Scott A. Hugo. The Company requests that the Commission authorize Consumers Energy to defer 2020 through 2023 costs related to the Karn 1 and 2 severance and retention agreement, utilizing a regulatory asset to record the deferred amounts and to recognize amortization expense of the deferred amounts beginning the year after costs are incurred and continuing through 2039, the estimated remaining life of Consumers Energy's remaining coal plants.

Q. What is the projected amount of deferred costs related to the retention separation agreement?

A. Based upon the current employee acceptance rate of the agreement, Consumers Energy estimates total O&M costs to be deferred at $27.4 million (Exhibit A-66 (DLH-1)) for the 2020 through 2023 period.

Q. How do you propose these costs be recovered?

A. The Company proposes that these costs be deferred through the closure of the plant in 2023. The deferred cost would be amortized beginning in 2021 through 2039. The 2021 amortization expense would be included in rates approved in this case. The deferred unamortized balance would be included in rate base and would earn a return at the authorized rate of return.

Q. Is there an alternative proposal to recover these costs?

A. Yes. The projected test year O&M costs for separation and retention could be included in the revenue requirement. See Exhibit A-83 (HJM-64) for the impact on the revenue requirement if the deferred approach presented in Exhibit A-66 (DLH-1) is approved.

PowerMIFleet EV Charging Deferred Accounting Proposal

Q. Does the implementation of the proposed PowerMIFleet EV Charging Program, discussed in Company witness Sarah R. Nielsen's direct testimony, require any specific accounting approval?

A. Yes. The proposed PowerMIFleet EV Charging Program ("EV Program"), if approved, would result in a deferred asset until the EV Program costs are fully collected. If this proposal is approved by the Commission, the Company requests approval to recognize a regulatory asset to record these deferred amounts.

Q. How does the Company propose to recover this regulatory asset?

A. If the Commission approves regulatory asset accounting for these costs, the Company would amortize each annual deferred amount over five years beginning the year after the cost is incurred. The resulting amortization expense would be included in rates. The deferred cost would be subject to review in rate cases and, following the review, the deferred unamortized balance would be included in rate base and would earn a return at the authorized rate of return. Company witness Nielsen discusses projected EV Program costs.

Q. If approved, how would the Company recognize ongoing incremental EV Program O&M costs?

A. If the Commission adopts the regulatory asset treatment, the Company will incorporate the annual incremental EV costs into the regulatory asset balance as they are incurred and will request recovery of the amortization of the incremental costs in succeeding rate cases.

Q. What specific accounting approvals are required if the Company's EV Program is adopted by the Commission?

A. If the EV Program is approved, the Company is requesting that the Commission: (i) authorize the recognition of a regulatory asset to recognize deferred EV Program costs; (ii) authorize the amortization of deferred EV Program costs over five years beginning the year after the costs are incurred; (iii) following a review of incurred costs in rate cases, include recovery of the resulting amortization expense in rates; and (iv) include the deferred net unamortized balance of EV Program costs in rate base.

Q. What is the alternative to this recovery approach?

A. The alternative recovery approach is to include projected test year program costs in rates for recovery.

<u>CVR Incentive Deferral</u>

Q. Does the CVR incentive presented by Company witness Michael J. Delaney require any specific accounting approval?

A. Yes. The proposed CVR incentive, if approved, would result in a deferred asset until the deferred amount is fully collected. The Company requests approval to recognize a regulatory asset to record these deferred amounts.

Service Restoration Deferral

Q. Company witness Brenda L. Houtz recommends that service restoration O&M expense in excess of $10 million over the amount set in rates should be deferred. Please describe the determination of the deferred amount.

A. Each calendar year, actual service restoration O&M expense will be compared with service restoration O&M expense approved for recovery in rates. Any actual service restoration O&M expense in excess of $10 million above approved amounts will be recorded in a regulatory asset. Should rates for more than one rate case be in effect for any given calendar year, the amount approved in rates will be calculated by (i) dividing the service restoration O&M expense approved in each of the two rate cases by the days in the corresponding test year, (ii) multiplying each resulting per day expense by the number of days in the calendar year that rates were in effect for the associated rate case, and (iii) adding the two resulting products together.

Q. Please describe the rate recovery of the regulatory asset.

A. Each year that actual service restoration O&M expense exceeds the service restoration O&M expense threshold, the associated deferred balance will be tracked. Each year will be tracked separately from other years. Each year with a balance will be amortized over ten years beginning with the year after the recording of the regulatory asset. The resulting amortization expense would be included in rates. The deferred costs would be subject to review in rate cases and, following the review, the deferred amortized balance would be included in rate base and would earn a return at the authorized rate of return.

Q. Does the service restoration deferral require any specific accounting approval?

A. Yes. The service restoration deferral, if approved, would result in a deferred asset until the deferred service restoration costs are fully collected. The Company requests approval to recognize a regulatory asset to record these deferred amounts.

FCM Recovery Mechanism

Q. Do the proposals for the FCM recovery mechanism presented by Company witness Heidi J. Meyers require any specific accounting?

A. Yes. The FCM recovery mechanism, if approved, would result in a deferred asset until the annual FCM revenues are fully collected. The Company requests approval to recognize a regulatory asset to record these deferred amounts.

Q. How does the Company propose to recover this regulatory asset?

A. The recovery mechanism proposal would result in a customer surcharge designed to collect annual FCM revenue within two years of recognition.

Q. Why is a two-year collection period important?

A. The FCM revenue falls under an alternative revenue program according to Accounting Standards Codification ("ASC") 980-605-25.

Q. What are the normal revenue recognition criteria?

A. ASC 606, *Revenue Recognition*, states that "an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services." Generally, the following criteria need to be met: pervasive evidence of arrangements exists; delivery has occurred or services rendered; the seller's price to the buyer is fixed or determinable; and collectability is reasonably assured.

Q. What is an alternative revenue program?

A. An alternative revenue program is for regulated utilities with alternative revenue pursuant to GAAP.

Q. What is alternative revenue?

A. Alternative revenue is generally segregated into two programs. The first program adjusts billings for the effects of abnormal weather patterns, energy conservation efforts, or from broad external factors such as a general recession. The second program provides for additional billings if the utility achieves certain objectives, such as reducing costs, reaching specified milestones, or improving customer service. Alternative revenue programs enable the utility to adjust rates in the future (usually as a surcharge applied to future billings) in response to past activities or completed events. The FCM provides a return on Power Purchase Agreements ("PPAs") approved by the MPSC as part of the competitive bidding process. Thus, the FCM provides for additional billings if Consumers Energy achieves certain objectives and, thereby, falls under the second type of program described above.

Q. What are the alternative revenue recognition criteria?

A. ASC 980-605-25 states that revenue recognition is appropriate when all the following criteria are met:

- Criteria A: The program is established by an order from the utility's regulatory commission that allows for automatic adjustment of future rates. Verification of the adjustment of future rates by the regulator does not preclude the adjustment from being considered automatic;
- Criteria B: The amount of additional revenues for the period is objectively determinable and recovery is probable; and
- Criteria C: The additional revenues will be collected within the 24 months following the end of the annual period in which they are recognized.

Q. Does the FCM proposal in this proceeding meet Criteria A?

A. Yes, Criteria A has been met. The Company's Integrated Resource Plan, approved by the Commission in its order issued on June 7, 2019 in Case No. U-20165, authorized an FCM for new or amended PPAs beginning January 1, 2019.

Q. Does the FCM proposal in this proceeding meet Criteria B?

A. Yes, the FCM recorded is objectively determinable.

Q. Does the FCM proposal in this proceeding meet Criteria C?

A. Yes, but only if the collection of the incentive occurs within 24 months from the period the incentive was recognized.

Q. What is the Company's proposed collection period for the FCM revenue?

A. The FCM revenue will be recognized on Consumers Energy's books when an approved collection mechanism has been established by an order in this case. In order to comply with the 24-month collection requirement of Criteria C, the incentive needs to be fully collected within two years of recognition. Once a collection mechanism is established, Consumers Energy intends to recognize the FCM in the year it is earned. For example, FCM revenues recognized in 2020 would need to be fully collected by the end of 2022.

Q. Why is it important to record the FCM revenue in the year with which it is associated?

A. It is important to record the FCM revenue in the same period that the related PPA costs are incurred to present the true economics of the program in Consumers Energy's financial statements. It also allows for consistent financial reporting as incentives will not be allocated over various financial reporting periods.

Q. What are the implications if the revenue is not fully collected within two years of recognition?

A. If the FCM revenue is not fully collected within two years, GAAP would require a determination that the revenue was recorded out of period and should have been recognized when billed to the customer. The requirements of ASC 980-605-25 stipulate that the revenue <u>must</u> be collected within 24 months and allows for no flexibility. Failing to collect the incentive within two years of recognition would then require a reversal of the revenue that was already recognized by the Company in prior years.

Q. What is Consumers Energy requesting related to the recovery period of the FCM?

A. Consumers Energy requests that the recovery approach outlined in Company witness Meyers' testimony be approved, which approach meets the two-year collection requirements outlined above.

<u>Demand Response Incentive Recovery</u>

Q. Does the Demand Response Incentive Recovery proposal presented by Company witness Steven Q. McLean fall under the alternative revenue recognition criteria that you previously discussed?

A. Yes. Just as with the FCM revenue, in order to recognize the Demand Response incentive revenue in the period earned, it is necessary to collect the incentive within two years of recognition. Company witness McLean provides a mechanism that, if approved, would meet the alternative revenue recognition requirements outlined above.

CVR Incentive Recovery

Q. Does the CVR Incentive Recovery proposal presented by Company witness Delaney also fall under the alternative revenue recognition criteria?

A. Yes. Just as with the FCM and Demand Response incentive revenue, in order to recognize the CVR incentive revenue in the period earned, it is necessary to collect the incentive within two years of recognition. Company witness Delaney provides a mechanism that, if approved, would meet the alternative revenue recognition requirements outlined above.

Accounting for Investments in Cloud-Based Technologies

Q. Why is the Company seeking the projected working capital rate-making treatment to support the adoption of cloud computing proposed by Company witness Jeffery D. Tolonen?

A. The move to utilize cloud computing results in an increase in prepaid expenses associated with cloud computing subscriptions or hosting fees. This differs from on-premise solutions since the fees typically include vendor computing infrastructure. Cloud-based solutions represent a transformational shift in the way to design, utilize, and invest in Information Technology ("IT"). As IT has continued to evolve, the capabilities of cloud-based solutions have enabled organizations to realize significant efficiencies as well as push the operational capabilities beyond that of traditional on-premise IT systems. Cloud-based solutions are generally classified into three different offerings: (i) Software as a Service; (ii) Platform as a Service; and (iii) Infrastructure as a Service. Depending on the offering type, the cloud-based solution provides one or all of the following: (i) software applications; (ii) underlying IT infrastructure; (iii) software maintenance; (iv) and administration as a service. These cloud-based technologies are hosted by the service provider in the cloud and not on the customers' on-premises IT infrastructure. The Company projects a significant increase in prepaid subscription or hosting fees associated with cloud-based solutions. Under the existing rate-making approach, these prepaid fees would only be included in historical working capital. Excluding projected prepaid cloud computing expenses from working capital creates a regulatory incentive to invest in on-premises software solutions which are projected in rate case filings. This creates financial hurdles that hinder utilities from realizing the benefits of cloud-based technologies. The ability to project the prepaid cloud computing costs in working capital removes the disparity in the rate-making treatments between on-premises and cloud-based solutions.

Q. Why are you requesting approval to follow FERC accounting guidance released December 20, 2019 in Docket No. AI20-1-000, *Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract?*

A. Under GAAP, the implementation costs associated with cloud-based solutions do not qualify for treatment as a capital asset. They are recorded as an "Other Asset" and recognized as historical working capital for rate-making purposes. This differs from the accounting for on-premise software which is recorded as a capital asset and included in plant for rate-making purposes. FERC addressed this disparity in accounting treatments between these two software solutions in the accounting guidance released in Docket No. AI20-1-000 and directs jurisdictional entities to account for cloud-based solutions the same as on-premise software. The Company requests that the Commission adopt the FERC accounting guidance for regulatory reporting and rate-making purposes.

Q. Are the requests related to cloud-based solutions specific to Consumers Energy's electric business?

A. No. These technology investments have the potential to serve both Consumers Energy's electric and gas businesses. Thus, the Company requests that the Commission provide authorization to utilize the projected working capital treatment and to follow the FERC accounting guidance consistently for both the electric and gas businesses.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

BRENDA L. HOUTZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Brenda L. Houtz, and my business address is 1935 West Parnall Road, Jackson, Michigan, 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Grid Management.

Q. Please describe your educational background and work experience.

A. I have a Bachelor of Business Administration from Huntington University located in Huntington, Indiana, and a Master of Business Administration from Spring Arbor University located in Spring Arbor, Michigan. I am Certified as a Reliability Coordinator by North American Electric Reliability Corporation ("NERC"). I have been in the electric utility industry for over 30 years. I started my career in 1990 with American Electric Power ("AEP") as a Station Mechanic building and maintaining electrical substations at voltage classes of 4,000 to 345,000 volts. After 11 years, I moved into the Transmission and Distribution control rooms as a controller for four years. I went on to distribution control room scheduling as a scheduler, and for seven years was the leader of the Distribution Dispatch Center in Fort Wayne, Indiana. The last two years with AEP I spent as Manager of Distribution Services for the Southwestern corner of Michigan. Over the last five years with Consumers Energy, my positions included Superintendent of High Voltage Distribution ("HVD") control room, Low Voltage Distribution ("LVD") Manager of the Company's southern headquarters, and now Executive Director of Grid Management.

Q. What are your responsibilities as Executive Director of Grid Management?

A. I am responsible for the safe and reliable operation of Consumers Energy's electric grid.

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

A. The purpose of this direct testimony is to support the projected service restoration cost. In the past three years, Operations and Maintenance ("O&M") expense for service restoration has averaged $65 million per year. See Figure 1, showing actual service restoration costs separated into cost types for 2015 through the first nine months in 2019, with the final three months of 2019 forecasted as of the time the figure was prepared. Preliminary actual costs for 2019 service restoration are now known to be approximately $92.1 million. These costs have increased due to an increase in weather/storm events, the need for Mutual Assistance ("MA") crewing, and implementation of the Incident Command System ("ICS").

Figure 1

Consumers Energy
Five Year Operation & Maintenance Expense
Service Restoration ('000)

				Year		9 Months + 3 Month Forecast
Line	Description	2015	2016	2017	2018	2019
1	OM&C Labor	$7,466	$7,462	$12,773	$12,605	$15,895
2	Contractor	$15,559	$9,247	$24,208	$18,963	$37,627
3	Exempt & Non-Exempt Labor	$2,141	$1,803	$4,520	$3,585	$5,436
4	Other Labor	$5,385	$10,035	$11,359	$9,346	$13,128
5	Business & Other Expense	$7,196	$6,046	-$3,737	$8,125	$9,514
6	Material	$419	$910	$1,048	$1,301	$2,070
	Total	$38,167	$35,504	$50,172	$53,924	$83,670

To adequately reflect the increasing cost of service restoration, and to enable the Company to effectively restore service to customers, the Company is projecting $65 million in service restoration costs in the test year and proposing a deferred accounting mechanism for any service restoration costs that exceed $75 million in a year. The projected $65 million expense for the test year is based on a three-year average of service restoration costs for 2017, 2018, and 2019, and accounts for the recent increase in weather events and the variable and unpredictable nature of these costs. In addition, this testimony will address the Company's progress in transitioning remaining residential customers to the Residential Summer On-Peak Basic Rate ("RSP") 1001 Summer Time-of-Use ("TOU") Rate, and propose that customers with non-communicating Advanced Metering Infrastructure ("AMI") meters not be transitioned to RSP at this time. Also, I will discuss projected costs for the purchase of land for a Unified Control Center ("UCC") project.

I. <u>Service Restoration</u>

Q. Why has Consumers Energy's service restoration costs increased over the last three years?

A. The increased cost is due to increased tree-caused outages, increased weather (wind and ice) events, ICS implementation, and increased cost for MA crewing. See Company witness Chris A. Shellberg's direct testimony discussing tree outage incidents.

Q. Please discuss the increased outages caused by weather.

A. Company witness Richard T. Blumenstock's direct testimony, Figures 6 through 8, show an upward trend in 35+ miles per hour ("mph") wind gusts over the past five years. At 35+ mph, significant gust-related outages generally begin to occur. In 2015, gusts in excess of 35 mph occurred over approximately 1,500 hours. And the trend has increased, with 2019 experiencing gusts above 35 mph over 2,400 hours. In the last four years, the Company has also experienced four ice events. Two of these ice events in 2019 resulted in significant service restoration O&M costs. When ice accumulates to over 0.25 inches on the electric lines, it weighs down the conductor causing stress on and damage to the components. During the thawing process, limbs from trees break off, lodging into and causing damage to equipment.

Q. Please discuss the implementation of ICS.

A. The implementation of ICS has improved the Company's ability to be a standardized emergency response organization with a scalable and flexible model to service restoration, allowing the Company to meet the needs of any emergency incident. ICS provides role clarity for all response personnel, aligns all response personnel to a single set of incident objectives, divides responsibilities into specific incident response functions to manage the incident (span of control), and allows for transfer of command as the event escalates and demobilizes. ICS allows the Company to plan; determine what equipment, resources, and logistics are needed; complete the necessary operations to restore power; and perform administrative tasks. Ultimately, ICS facilitates the balancing and optimization of resources, response time, safety, and other key factors that benefit both our customers and our crews during outage and emergency events.

Q. Please discuss the need for additional MA crewing.

A. Due to the increase in weather activity, additional crewing has been needed beyond the Company's current internal in-state and contract crew workforce. When major/catastrophic events take place, the Company will reach out to MA crews to assist in providing the necessary resources to achieve the targeted restoration time for customers. Most of these crews are from out of state and require lengthy travel time and lodging during their stay, which increases the restoration cost in the more severe restoration events. Without the assistance provided by these crews, restoration time would be significantly delayed.

Q. What is Consumers Energy's service restoration philosophy?

A. Prior to 2019, Consumers Energy operated a hybrid ICS model with three Work Management Centers ("WMC") (Grand Rapids, Jackson, and Saginaw) that were staffed with logistics, a restoration director, distribution and wire down dispatchers and a dispatch supervisor, and an Emergency Operations Center ("EOC") staffed with approximately six employees. In 2019, Consumers Energy fully implemented ICS, which included filling additional positions in both the EOC and WMCs.

Consumers Energy's continual development of ICS has resulted in dividing storm restoration into two components: pre-staging and restoration work. Pre-staging for a predicted weather event requires placing the necessary resources (such as crews and support) on standby for the pending event or on site in preparation for the event. Weather data and past incident numbers are utilized to determine span of control and staffing needs for each storm prediction and the ICS model is filled as needed in pre-staging. As the event enters the Company's service territory and incident count changes, the span of control will adjust to the event, which is one of the benefits of the ICS. During a storm, the focus is to Isolate, Restore, Repair ("IRR"). Crews will first isolate damaged sections of the grid to allow safe work to begin. Next, crews focus on getting customers' power back on, which at times may require a temporary fix. These temporary fixes allow the customer to be restored and make the site safe, but then require a specialized crew with the right materials to follow up for the specific type of damage after all impacted customers have been restored.

In general, additional Company and contract crews are sought as outages ramp up to the 15,000 customer-impact level. These crews are leveraged to provide necessary field resources, such as to relieve police and fire personnel who guard downed wires, to address critical customers such as hospitals and schools, to make downed wires safe, and to restore power to customers.

Q. Has there been an increase in staffing costs?

A. Yes. With the implementation of ICS, pre-staging costs for support staff have increased due to the number of resources, overtime, and premiums paid to responders (see Figure 2 below for 2019 staffing costs). Pre-staging took place 29 weeks out of the year in 2019 with an O&M cost totaling $3.2 million for premiums and overtime incurred from exempt and non-exempt support staff in WMCs and EOC coverage. Prior to 2018, almost 600 employee resources filled positions for storm events as needed, and they were not placed on call 24/7 (see Figure 3). With the current ICS model that started in 2019, over 900 employees are needed to fill the positions that allow for 24/7, 365-day coverage.

Figure 2

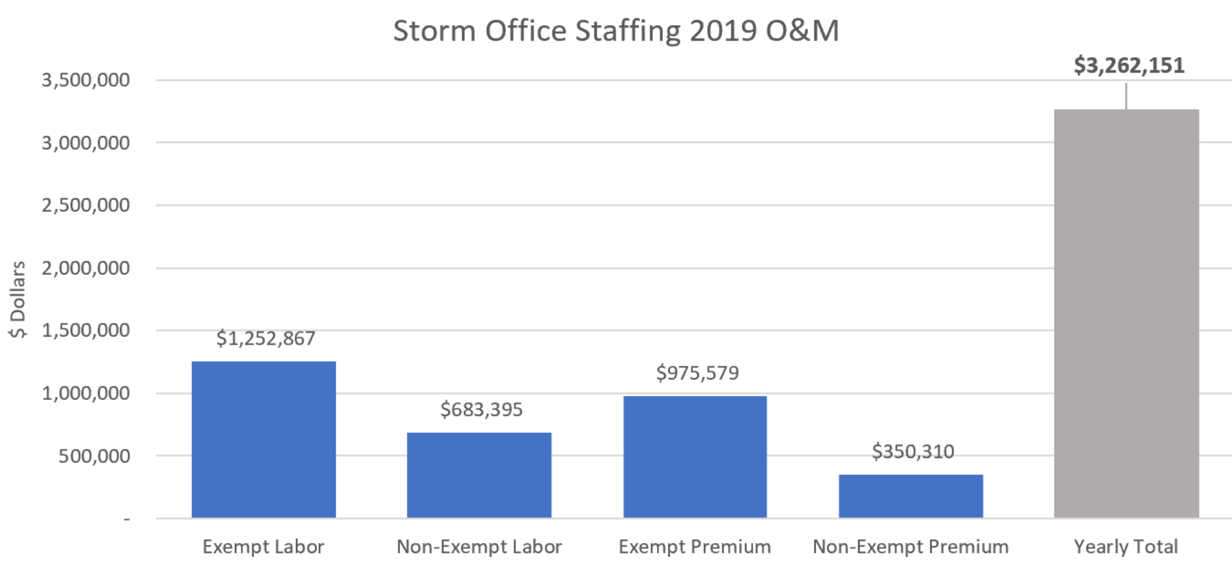
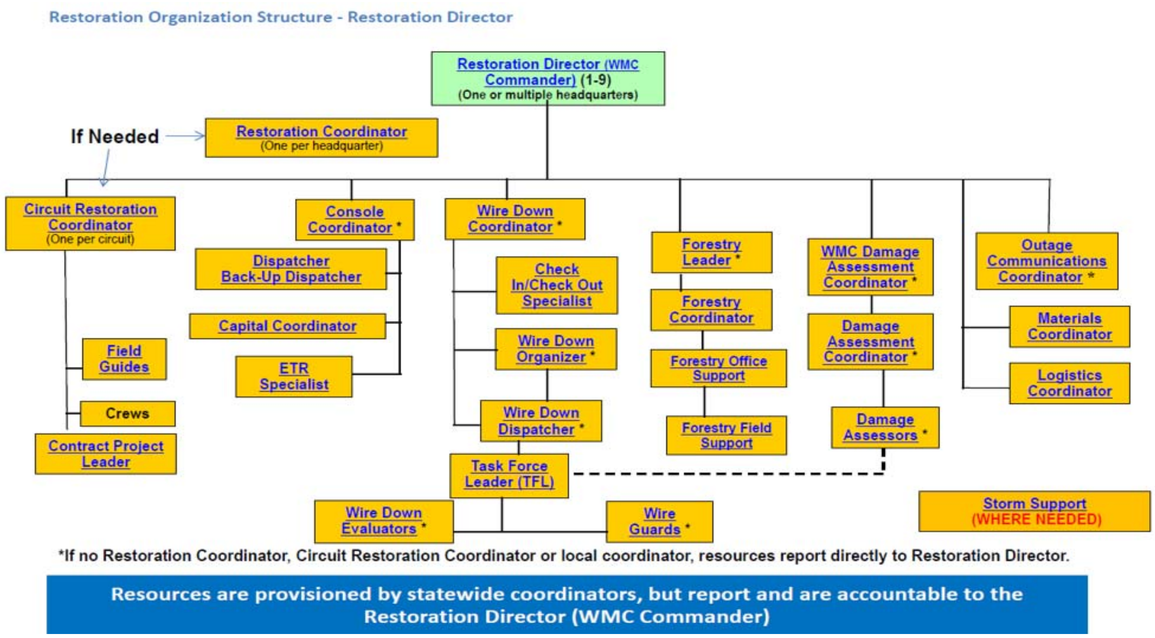


Figure 3



As recommended by the Michigan Public Service Commission ("MPSC" or the "Commission") in Case No. U-18346, Consumers Energy fully implemented the ICS model to allow for more streamlined processes with state/local/emergency responders during catastrophic events. This model required additional resources to support the span of control including setting up an EOC. The organizational charts below (see Figures 4 and 5) are a representation of the new ICS model implemented in 2019.

Figure 4

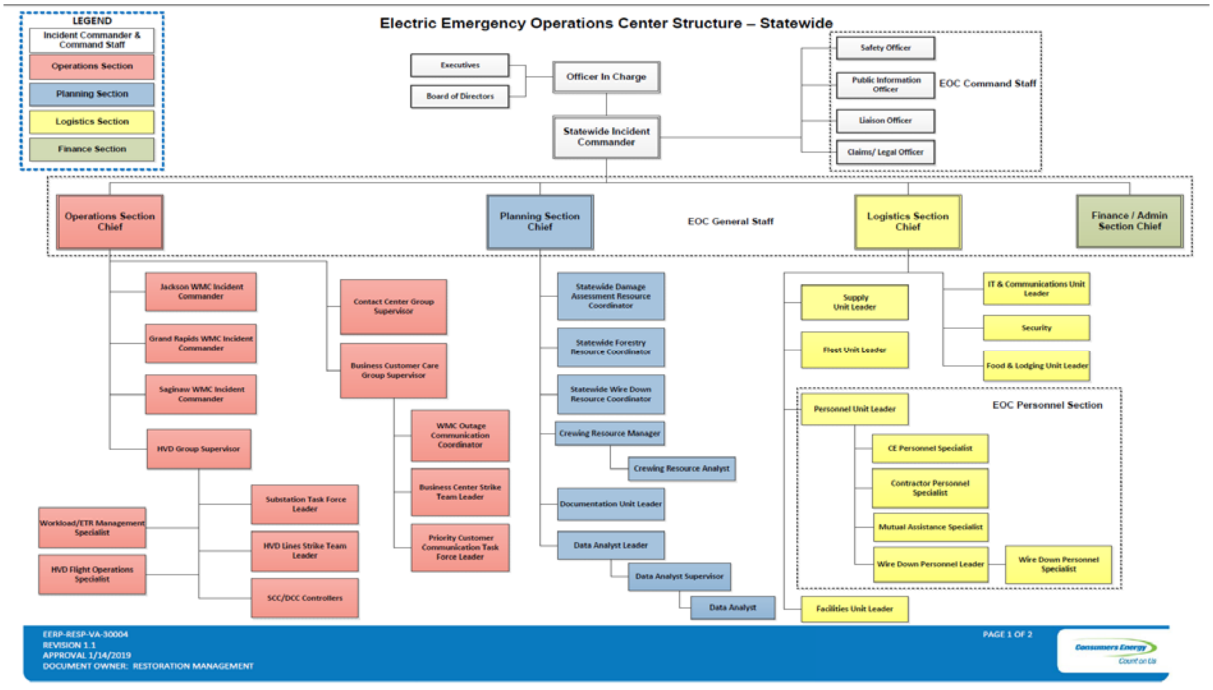
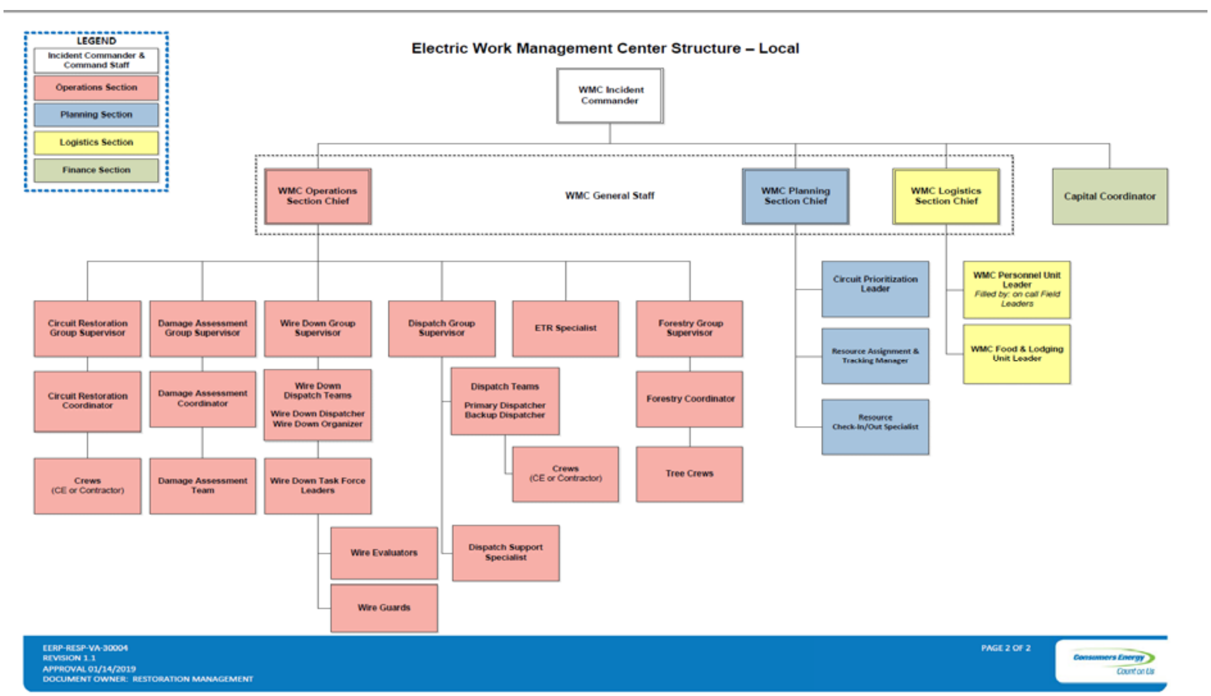


Figure 5



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Q. Please describe Consumers Energy's pre-planning activities.

A. Consumers Energy works with meteorologists from Telvent Data Transmission Network ("DTN") to anticipate weather patterns and the potential for severe weather. Consumers Energy and DTN then utilize historical outage data to determine the expected number of service interruptions, electrical hazards, and customers impacted based on the forecast. After determining the potential system and customer impact, the Consumers Energy Restoration Management Team will identify what roles are needed to fill in the ICS model and secure necessary office staffing for predicted crewing levels during pre-staging activities to allow for 24-hour coverage for the duration of the event. When determining crewing levels, Consumers Energy uses a four-step approach. The first step is to use Consumers Energy crews; the second step is to use contractors that regularly perform planned work on the Company's system; the third step is to use storm contractors (specific contractors used for response to storm events on the Company's system); and the last step is to use MA crews. With the exception of MA, the remaining crews are capable of being on call, pre-staged, and deployed throughout the service territory. Consumers Energy assumes three incidents can be addressed per crew working a 16-hour shift and 10 downed wires ("WDs") can be made safe (by either relieving police or fire personnel or disconnecting the broken wire) for every Electric Single Worker ("ESW"). These considerations determine the number of crews needed for each event.

Q. Please provide examples of recent events and the Company's response.

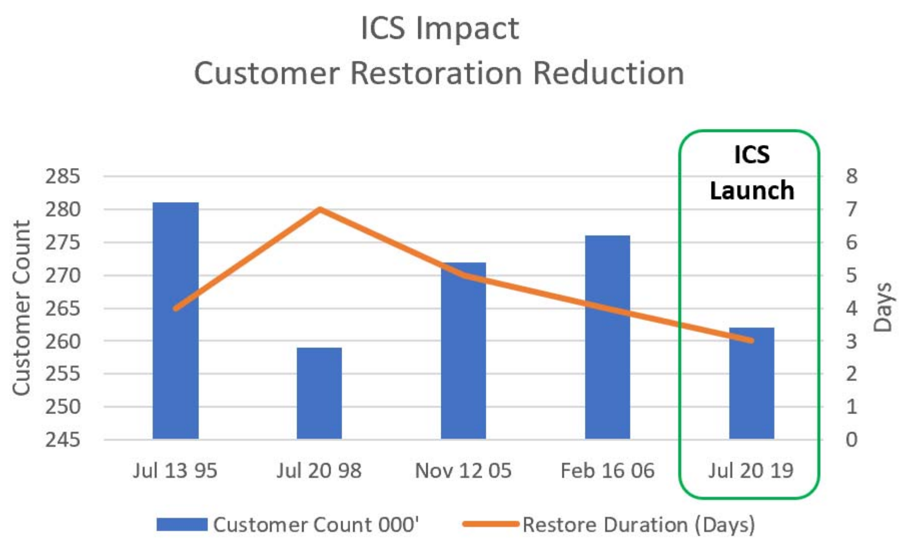
A. Between February 5 and February 8, 2019, the Company was impacted by two significant ice events coupled with wind gusts of 50-55 mph. Icing of almost 0.50 inch across many areas caused 249,000 customers to lose power. Using the Company's ICS, pre-planning for this weather event began on the weekend leading up to the storm. Decisions were made to secure additional crewing resources including contractors and MA along with pre-staging office personnel to be able to quickly support field operations. After the event, the Company was recognized by the Edison Electric Institute ("EEI") and awarded the Recovery Award for its quick response to safely restore customers.

Between July 19 through July 20, 2019, two severe thunderstorms caused 231,000 of Consumers Energy's customers to lose power. Wind gusts were recorded between 50-80 mph. Again, the ICS model was successfully used to secure and activate resources prior to the storm. By pre-staging, the Company quickly began mobilizing crewing resources and started restoration efforts in the early morning hours of July 20. This event was the 22nd worst storm associated with lightning and high winds in the Company's 30+ years of recorded storm history, and the Company restored customers in less time than previous similarly sized events (see Figures 6 and 7 below). The Company was again recognized by the EEI and awarded its second Recovery Award in 2019 for its timely response to safely restore customers.

Figure 6

STATS	7/13/1995	2/16/2006	11/12/2005	7/20/19	7/20/98
Incident/Customer Counts Jan-1975 to July 2019	19th	20th	21st	22nd	23rd
Number of Customers	281,000	276,000	272,000	261,572	259,000
Restoration days (range only)	7/13-7/17	2/16-2/20	11/12-11/17	7/20-23	7/20-7/27
Weather Type	Lightning High Winds	High Winds Ice	High Winds	Lightning High Winds	Lightning High Winds

Figure 7



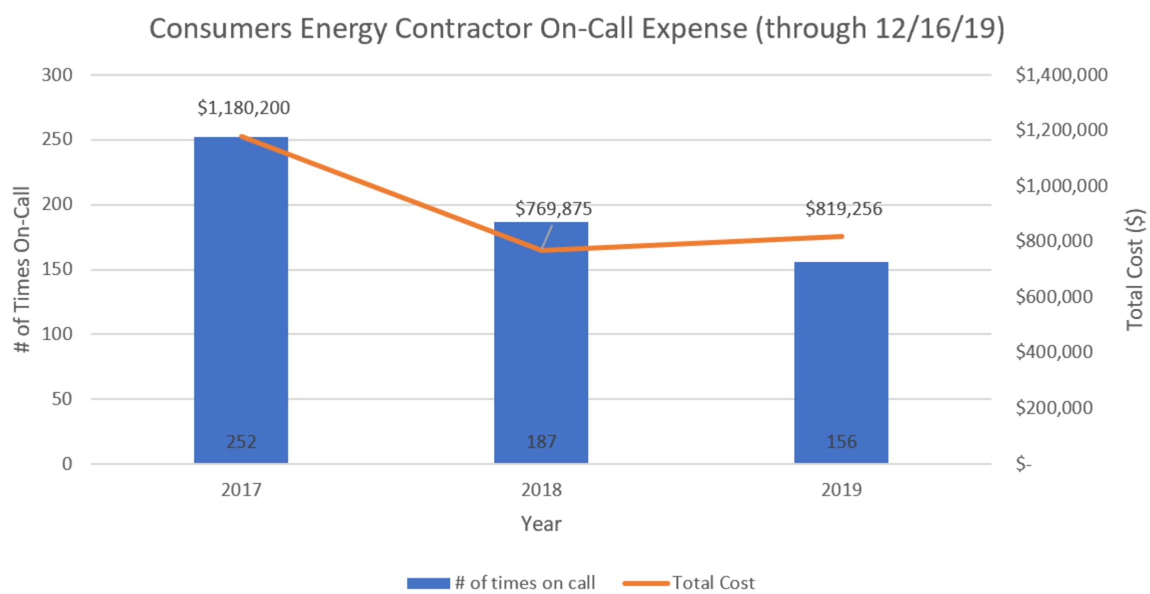
Q. What size events can Consumers Energy resources address prior to utilizing outside staffing/crewing?

A. In general, the Company assumes availability of approximately 140 crews and 60 ESWs (depending on vacations, sick leave, and training). This level of field resourcing allows for 420 incidents to be completed in a 24-hour period prior to needing additional resources. Some Consumers Energy crews must remain in their home headquarters to respond to emergent issues in non-impacted headquarters.

With ICS, span of control needs to be considered for crew to dispatcher ratio. Each experienced dispatcher can handle 15 to 20 points of contact with field personnel. To control the number of points of contact, Field Leaders obtain work from dispatchers. Field Leaders will then have five to seven crews reporting to them to issue work, which allows for a greater span of control and more efficiencies with field personnel.

Since implementing ICS, Consumers Energy has improved its prediction model with DTN and streamlined its process for placing contractors on call (see Figure 8 below).

Figure 8

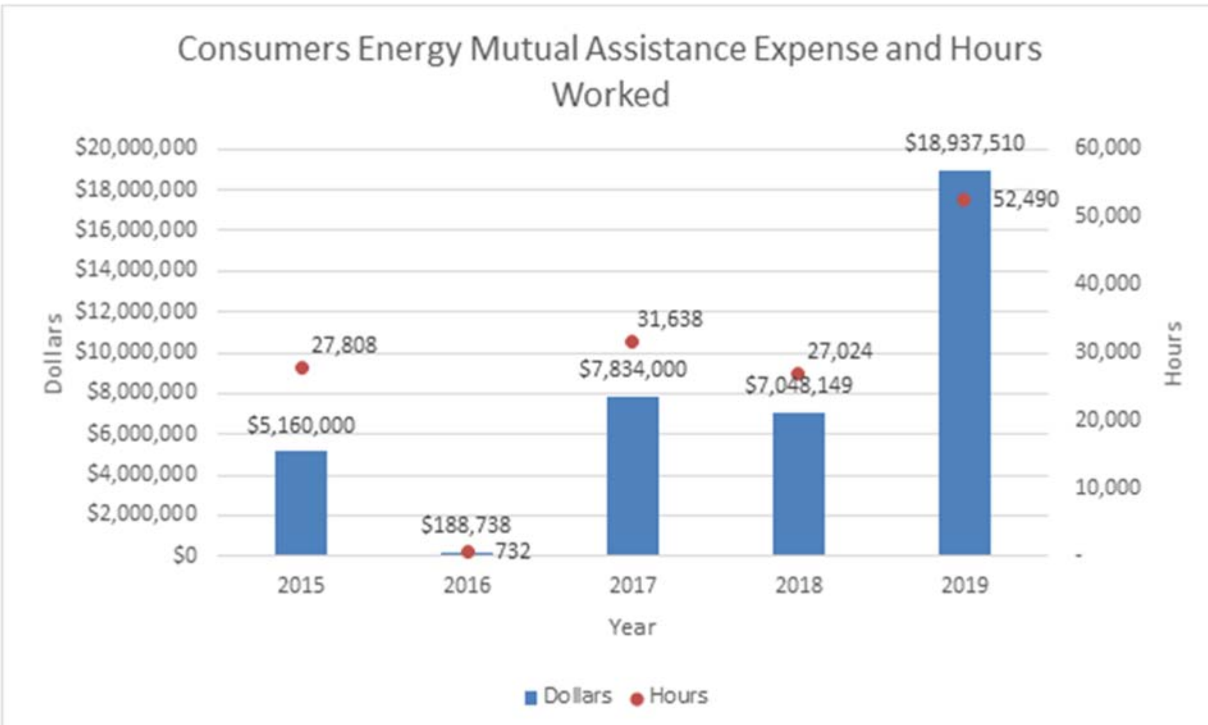


Q. How does Consumers Energy determine when MA is requested?

A. MA crews are obtained from other Investor Owned Utilities ("IOU"). Expense and hours worked for MA crews from 2015 through 2019 are shown in Figure 9 below. The cost associated with this crewing type has increased over the last year. This crewing type is deployed when all other resources (Consumers Energy crews, in-state contractors doing planned work on the system, and storm contractors) have been engaged and the incident count is greater than current crew capacity can handle to meet the estimated time of restoration.

In 2019, Consumers Energy had two catastrophic events that reached a Level 3 ICS classification resulting in the activation of MA crews. As seen in Figure 9, an O&M expense of almost $19 million resulted from having these types of crews assist with restoring service to customers, including over 52,000 hours of restoration work. This is compared with the expense of approximately $8 million over 31,000 hours and $7 million over 27,000 hours for MA crews during service restoration in 2017 and 2018, respectively. Due to the cost associated with MA crewing, these crews are the first field resources released at the beginning stages of demobilization.

Figure 9



Q. Why are costs higher for obtaining MA crews?

A. Great Lakes MA is a voluntary partnership of investor-owned electric companies across the country committed to helping restore power whenever and wherever assistance is needed. The host utility is required to cover funding for these crews upon acceptance. These costs include per diems, travel, meals, hotel, and staging costs for parking vehicles for rest periods. From the time of activation, MA crews are paid at a double-time rate for all hours worked or while on standby.

Q. What are the challenges to obtaining MA resources?

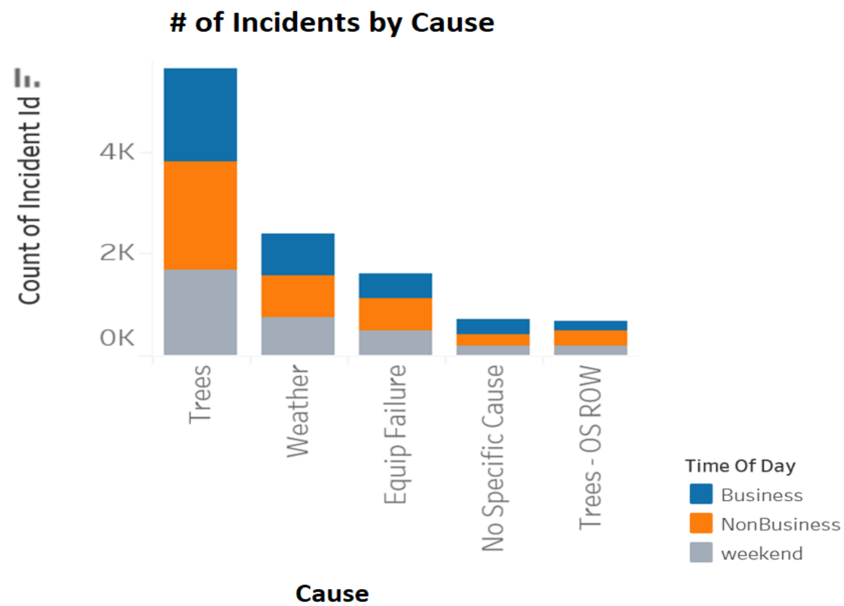
A. During pre-staging, many factors must be considered, such as available resources, time constraints, and the possibility of achieving the desired outcomes. Data is obtained from prior events to determine resource needs to meet the objectives set forth in the pre-staging activities. Ideally, resources will be on site, nearby, or enroute prior to the event impact. Consumers Energy will then turn to the EEI ramp-up tool, which is a method for allowing other utilities to share resources. EEI is an association that represents all United States IOU electric companies. However, the ramp-up tool does not always allow utilities to select crews that are in close proximity to the service territory. As other surrounding utilities are impacted, the available resources are being absorbed. This will require Consumers Energy to reach out geographically further for resources causing additional costs for travel. If resources are not obtained prior to the event entering the Consumers Energy service territory, costs may be significantly higher as surrounding utilities absorb crews from around the state and adjacent states.

Q. What are the biggest contributing factors for service restoration outages?

A. Consumers Energy's top drivers for service restoration outages are trees and weather (see Figure 10 below). Company witness Shellberg discusses tree-caused outages, which are the primary cause of outages.

As to weather-related outages, ice and wind gusts over 35 mph are the largest contributors to outages and have depicted an upward trend over the last five years.

Figure 10

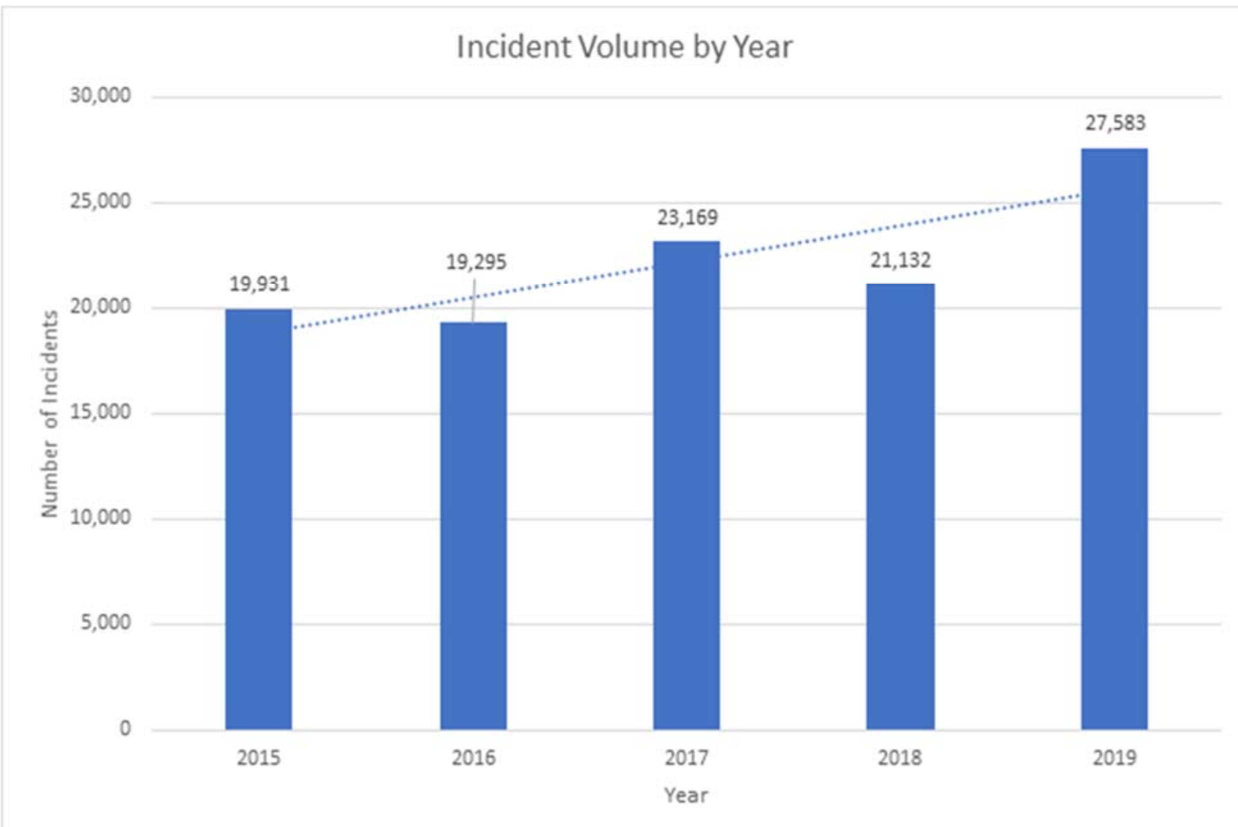


Q. What is the trend in weather patterns related to wind?

A. Weather patterns related to wind speed have been on the rise based on data selected from 21 automated observation stations that cover the Company's electric service territory (see Figure 5 in Mr. Blumenstock's direct testimony). These stations are typically located at airports and National Weather Service forecast offices. Figures 6 through 8 in Mr. Blumenstock's direct testimony show the number of hours when the 21 stations observed sustained winds and wind gusts exceeding 35 mph. Based on this data, 2019 has been the windiest year in recent history, following an upward trend over the past five years. The high wind speed threshold chart (see Figure 6 in Mr. Blumenstock's direct testimony) is based on winds averaged over a two-minute period, which may not capture the brief gusts that can also cause outages. The observation stations note gusts when there are rapid fluctuations of 10 mph or more between peaks and lulls over a ten-minute window. The gust speed is the maximum wind speed observed in that window. Also, 2019 has been the gustiest year in the past decade. Not only have the overall number of observations increased, but the number of 45 mph and 50 mph gusts are on the rise.

In 2015, Consumers Energy's territory experienced over 1,600 hours of 35+ mph wind gusts with 2019 capping out at over 2,300 hours of wind gusts in excess of 35 mph (see Figure 7 in Company witness Blumenstock's direct testimony). These tree outages, wind gusts, and weather patterns have been a contributing factor to an increase in incidents trending upward by 7,600 over the last five years (see Figure 11 below).

Figure 11



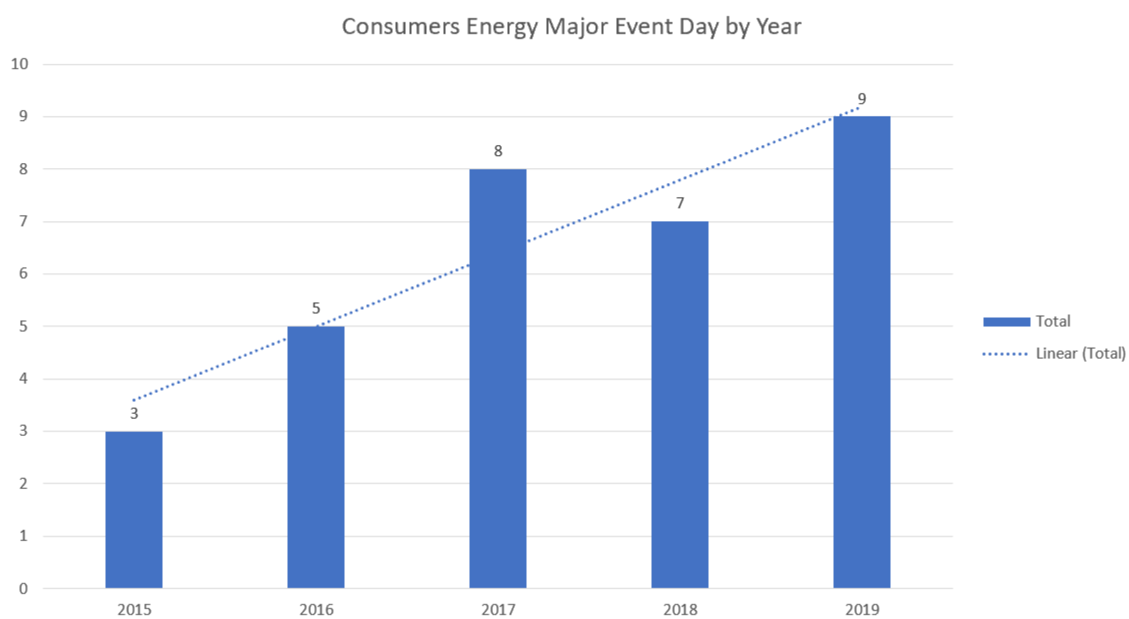
Q. What resources does the Company use to obtain/predict weather related events?

A. The Company uses DTN to obtain and predict weather related events. In the United States, DTN is the largest provider of weather services to the power industry and is the most experienced private meteorological company. DTN provides detailed, localized weather forecasts and real-time, mission-critical weather information. Consumers Energy is currently working with DTN to build an outage prediction model from historical weather events (ice, lightning, and wind) to improve pre-staffing efficiencies.

Q. Has there been an increase in the number of major and catastrophic events?

A. The Company has noticed an increase in the number of Major Event Days ("MEDs") declarations and catastophic events over the last five years. An MED is a day for which the reliability metrics for outages initiated on that day are excluded from the Company's statistics, in accordance with Institute of Electrical and Electronics Engineers ("IEEE") Standard 1366-2012, which defines MEDs based on five sequential years of daily outage minutes. Catastrophic events are classified by the MPSC performance standards as any weather event that impacts 10% or more of a utility's customers, or events of sufficient magnitude that result in issuance of an official state of emergency declaration by the local, state, or federal government. In 2019, the Company experienced its largest number of MEDs (see Figure 12 below) as compared to the previous four years. In 2017 and 2019, two catastrophic events occurred with 2018 experiencing one Catastrophic event.

Figure 12



Q. What is the most common threshold for customer outages?

A. As previously discussed, the Company identifies four levels of incident classification. Level 0 is routine day-to-day emergent work that Company crews address at the local level. Level 1 indicates an incident escalated beyond the capabilities of normal operation and requires additional resources to support the event including opening the WMC. This escalation can be required as a result of the incident count being in excess of field and office resources. The WMC allows for additional resources to be managed in a reasonable span of control with five to seven direct reports to one leader. Level 2 classification takes place when the incident escalates beyond the capabilities of the WMC or multiple WMCs are involved. At this point, the EOC is activated. The EOC is staffed and assumes command of the event allowing for additional resources to be deployed throughout the state to the impacted WMCs. Level 3 classification is a full crisis incident that requires full activation of the Company's response organizations to effectively manage the incident. At this point, MA is needed to handle the volume of the incident to minimize the duration of the outages.

On average, a Level 2 classification for ICS is activated at the 15,000 customer outage count. Over the past five years, there has been an upward trend for these Level 2 or higher events (see Figure 13 below).

Figure 13

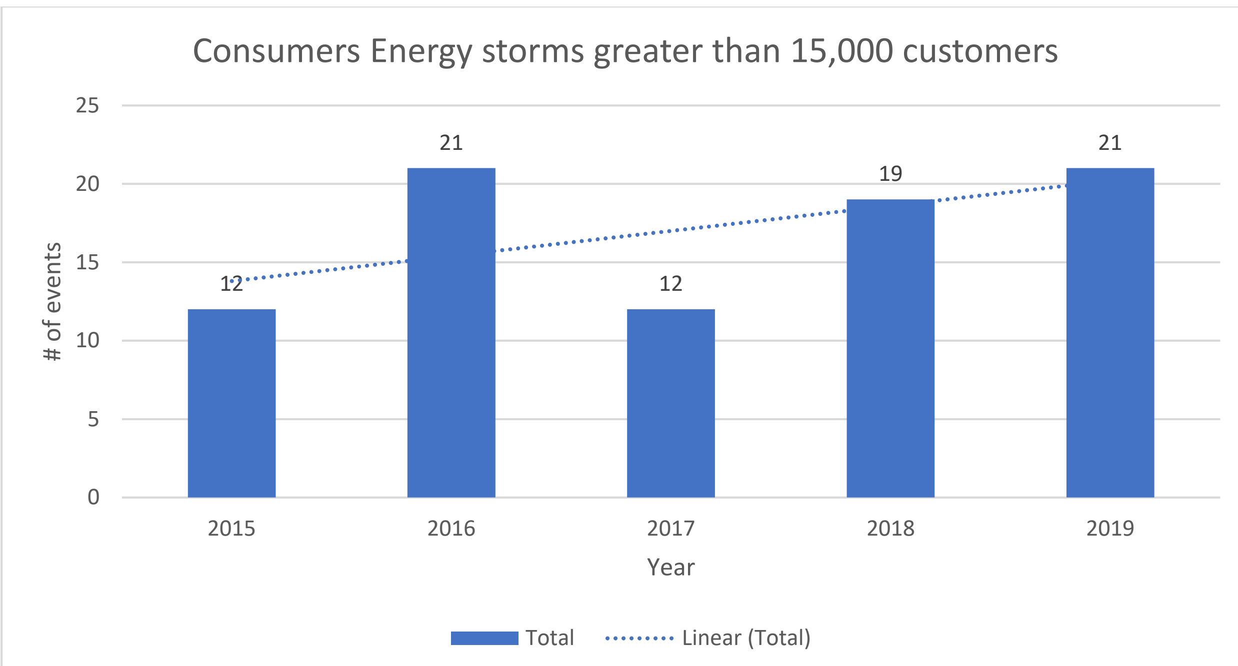
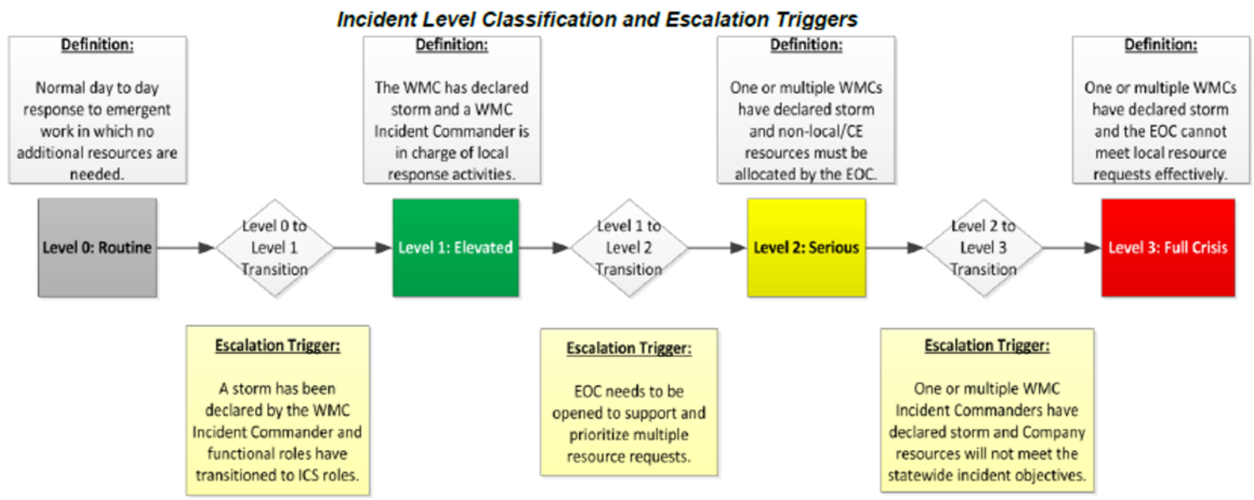


Figure 14



Q. What has historically occurred when Consumers Energy's service restoration costs are higher than what has been projected and approved in rate cases?

A. The Company has historically carried storm insurance to assist with costs incurred during catastrophic storms. There have only been two occasions in 20 years where Consumers Energy has recovered the cost of the premium due to claims. Please see the direct testimony of Company witnesses Karen M. Gaston and Daniel L. Harry discussing the Company's decision to not renew the storm insurance policy and proposal to "self insure" via deferred accounting treatment. With this deferral, the Company's customers only pay for costs projected for actual service restoration.

In addition, the Company may need to reduce spending in other areas of the Company to cover unavoidable storm restoration costs that exceed the planned costs. This can impact areas such as Grid Modernization, Planning, and Design programs.

Q. What is the Company's proposal for recovery of service restoration costs in this case?

A. The Company is projecting $65 million in service restoration costs in the test year based on a three-year average of service restoration costs for 2017, 2018, and 2019, which accounts for the recent increase in weather events and the variable and unpredictable nature of these costs. The Company also proposes a deferred accounting mechanism for any service restoration costs that exceed $75 million in a year.

Q. What are the benefits of the Company's projected service restoration spending and proposed deferred accounting mechanism?

A. One benefit of the projected service restoration expense and deferred accounting is the continued support of the ICS model. In comparing storms addressed with ICS to prior years without ICS, the Company has been able to restore more incidents and customers in less time compared to prior events of similar weather and crewing patterns (see Figure 15 below).

Figure 15

STATS	7/6/17	8/26/18	7/20/19
Number of Incidents	2565	4635	4177
Number of Customers	181,620	255,763	261,572
Restoration Duration in Hours	100	165	101

With the Company's proposals in this case, Consumers Energy expects customers to continue to experience improvement in restoration activities. As System Average Interruption Duration Index ("SAIDI") is reduced, so will the impact to societal cost.

Adequate staffing and implementation during level 2 and 3 incident classifications will shorten the duration of outages while targeting safety issues (wire down/police/fire) and restoring critical infrastructure. Additional ESWs allow for the relief of police and fire response personnel standing by on hazards in a timelier manner. ESW response with wire down guards can be deployed to secure these hazards. Additional crewing will allow for addressing issues with priority/critical infrastructures such as hospitals, nursing homes, and water/sewer stations.

In 2019, with the full adoption of ICS, the Company achieved the following reliability numbers for MED and catastrophic events: SAIFI 1.582, SAIDI 691.1, and CAIDI 436.8.

According to the Interruption Cost Estimate ("ICE"), these interruptions resulted in an estimated $2.5 billion community economic cost, which amounts to $3.6 million per SAIDI minute.

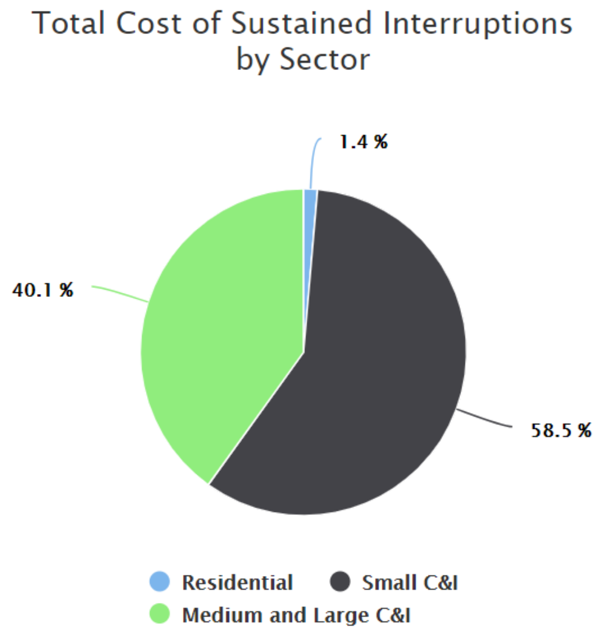
Figure 16

Inturruption Cost Estimates

SAIFI	SAIDI	CAIDI	#Residential	#Non-Residential
1.582	691.1	436.8	1,590,000	220,000

Michigan

Sector	# of Customers	Cost/Event (2016$)	Cost/Avg kW (2016$)	Cost/Unserved kWh (2016$)	Total Cost (2016$)
Residential	1,590,000	$13.82	$14.95	$2.05	$34,770,712.15
Small C&I	197,620	$4,693.05	$1,264.96	$173.76	$1,467,209,474.15
Medium & Large C&I	22,380	$28,367.56	$228.17	$31.34	$1,004,358.060.01
All Customers	**$1,810,000**	**$875.30**	**$317.76**	**$43.65**	**$2,506,338,246.32**



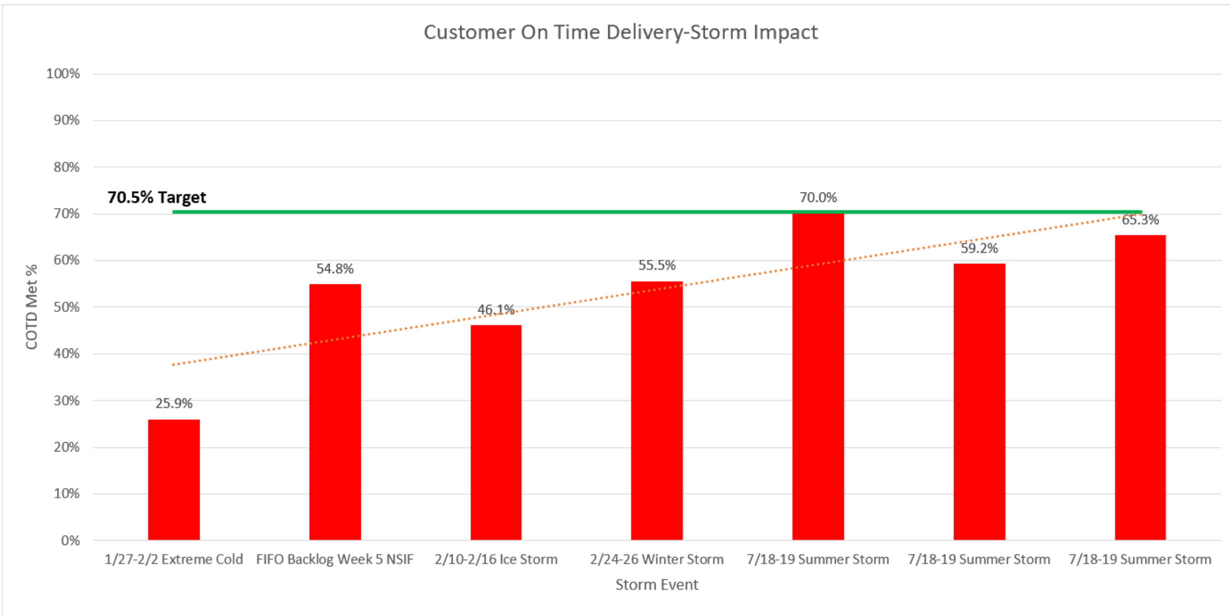
By not pre-staging, it would take approximately four hours to get Consumers Energy resources on site and working, thus increasing the duration of outages and the societal cost to customers. Pre-staging allows for the Company to continue to drive down wait time for resources to arrive on site to perform work.

The Company's service restoration proposals will allow for the necessary staffing to fulfill roles within the ICS structure to allow for greater span of control, communication with external entities (civil authorities), alignment on objectives, and managing of resources.

Q. Do service restoration efforts impact efficiency?

A. Yes. Customers not only lose power during restoration events, but often these events require delays in meeting customer committed work. During the February and July 2019 catastrophic restoration activities, Consumers Energy timely completed on average 50% in February and 70% in July of its customer committed work (see Figure 17 below). When crews are tied up on restoration activities, they cannot address the customers' needs for new service. This further supports the Company's efforts to improve service restoration times.

Figure 17



Q. What are examples of how other utilities recover service restoration costs?

A. The Company is aware that utilities in other states such as Alabama, Arkansas, Kentucky, Illinois, Florida, Ohio, Oklahoma, and Pennsylvania use mechanisms such as riders, reserve accounts, or securitization as part of their service restoration cost recovery.

- Rider – Allows recovery of storm damage O&M costs outside the general rate case.
- Reserve Accounts – Accounting mechanism that provides for the recovery of a specified annual amount that is used to offset costs incurred in the event a qualifying major storm occurs. These storm reserves pay for uninsured losses with funds allocated to a reserve account on an accrual basis.

- Securitization - Financing mechanism authorizing the utility to issue bonds for the purpose of recovering costs related to storms.

II. Residential Rate Type For Non-Communicating AMI Meters

Q. Were all remaining residential customers with AMI meters converted to RSP 1001/Summer TOU Rate in January 2020?

A. No. The Company worked diligently to transition customers taking service on the inverted block Residential Service Secondary Rate ("RS") to the RSP in January 2020, and transitioned the overwhelming majority of customers to the new RSP Rate. However, there are some customers who were excluded from the January 2020 transition for technical reasons. These customers include those that have opted out of an AMI communicating meter. In addition, the Company does not have a technology solution for moving RS customers who participate in the Net Metering Program to the new RSP rate. A technology solution is being developed which would enable Net Metering customers to be transitioned to RSP, but completion is not expected until later in 2020. In addition, there is a group of customers from whom the Company is unable to obtain consistent communications from the AMI meter, and the Company is proposing to exclude this group of customers from the transition to RSP.

Q. Why is the Company proposing to exclude customers where consistent AMI communications cannot be obtained?

A. Consumers Energy is proposing this exclusion to avoid creating billing issues, including estimated billings, for this group of customers. Over 99.8% of AMI meters provide consistent and reliable readings that are utilized for customer monthly billing. However, not all AMI electric meters communicate 100% of the time. Cellular signal strength and time of year impacts the meters' ability to provide reliable daily data required for actual billing. Currently, if a meter is not being read over the air, but rather by a meter reader, no intervals are collected, preventing those customers from effectively being billed on the RSP rate. There are currently approximately 6,000 customers with poor or non-communicating AMI meters that would be excluded from the RSP rate. These customers will not be able to receive a bill if they are transitioned to RSP. Therefore, the Company is proposing that they take service under the new Residential Service Secondary Non-Transmitting Meter ("RSM") rate, which mirrors the current RS rate. This will ensure that these customers continue to receive a monthly bill that is based on their actual energy use.

Q. Are there plans to address the non-communicating meters?

A. Yes. The Company will continue to seek workable and cost-effective solutions to address these non-communicating meters. Through normal improvements in technology, the Company anticipates the communication with meters will continue to improve. With the replacement of old technology in the 3G meters with newer 4G technology, Consumers Energy has already seen the overall communication rate increase. Improvements in the wireless signals in the telecommunications providers service territories will also have a positive impact. Outside of normal technological advances, Consumers Energy also plans to investigate cost-effective solutions that would allow intervals to be pulled manually in order to offer a consistent billing experience. The Company will continue to study and evaluate cost-effective solutions that may allow these customers to be served under the RSP rate.

Q. How will the Company select customers who will take service under the new RSM rate?

A. As reflected in Company witness Rachel L. Barnes' Exhibit A-23 (RLB-1), the Company considers customer experience a priority when determining if a customer should be on Rate RSM. Prior to the RSP rate, a smart meter needed to communicate once per billing cycle in the billing window in order to have an actual read for the bill. With the transition to RSP, a customer's experience is greatly diminished if the meter does not provide data every day. An algorithm was developed based on percent of reads and gaps in data, which are a direct correlation to billing success and customer satisfaction. Consumers Energy currently defines the following as a "poor communicating meter" if the symptom persists after troubleshooting and recommends that customers with these meters take service under the Rate RSM:

1) Meter has never communicated.
2) Meter has not provided a read in 20+ days.
3) Meter has two or more 5+ day gaps of data in the last 6 months.
4) Meter has had less than 89% in communicated reads in the last 6 months.

As individual customer experiences are evaluated, and system improvements are implemented, the Company will continue to fine-tune these criteria. It is expected the criteria will change over time in order to balance sustainability, repeatability, and customer experience.

III. Unified Control Center

Q. Please describe the Company's plan for a UCC.

A. Consumers Energy's Electric Grid Integration plan integrates cleaner, leaner, more modular sources of electric supply with electric grid enhancements engineered for customer value. To improve the service and response to customers' needs, the Company is addressing current limitations arising from the increasingly fast-paced and changing energy environment. One area of improvement involves how the Company operates across the electric sector with coordinated agility, but in recognition that security and operability is necessary through events such as catastrophic weather and external physical or technological threats. The need to address how the Company controls the electric grid and electric supply through fortified facilities and associated infrastructure is critical to fulfilling the needs of customers. Consumers Energy is beginning a UCC project to mitigate the risks in operating within this energy sector. As part of this project, the Company is projecting in this case $1 million to complete concept scope, the facility site requirements, and property selection and acquisition in 2021 as shown in Company witness LaTina D. Saba's Exhibit A-94 (LDS-3).

Q. Please describe the current Consumers Energy Control Center operation?

A. The current Consumers Energy control center operation comprises two major groups involving the electric grid and electric supply. The buying and selling of electricity is monitored and controlled through the Merchant Operations Center in Jackson. The electric grid is monitored, controlled, and dispatched by multiple operational centers with two control centers: the System Control Center ("SCC") in Jackson which handles Transmission and HVD lines and the substation network of 138 kV and 46 kV systems;

and the Distribution Control Center ("DCC") in Grand Rapids which handles the 46 kV substations feeding the LVD overhead and underground line system, including some of the 3-phase LVD system and the metropolitan system. The LVD overhead and underground line distribution system not covered by the DCC is dispatched from three LVD dispatch centers, one each in Grand Rapids, Saginaw, and Jackson.

With these current operations, there are separate configurations for addressing emergency events, and the space and tools used for such focused approach are limited or non-existent.

Q. What is the purpose of the UCC Project?

A. The UCC Project is aimed at bringing two of the major electric system and electric supply groups together and incorporating an emergency operations center function into a coordinated center by constructing a modernized hardened facility designed using current industry security, resiliency, and operability standards. This new facility will allow coordinated business continuity plans, with flexible and expandable utilization of a corporate ICS methodology across the Company's energy systems. The existing electric control and dispatch centers were built as early as the 1950s and 1960s and pose limitations that the UCC Project will address.

Q. How will customers benefit from this project?

A. Customers will benefit from reduced risk in the event of a catastrophe. The Company also expects the UCC project to result in faster restoration times, particularly during storms and unique events affecting these groups. The ability to understand system conditions and dispatch resources to address issues will be greatly enhanced by the technology available in the new facilities and the co-location of system operators and dispatchers. The UCC will also be far more resilient and hardened to adverse natural and man-made disasters, allowing critical utility operations to recover much more quickly in the case of a major catastrophe. The UCC will offer the opportunity for scalability and operability in running these systems through consolidation, potential reduction of span of control, and gained efficiencies.

In support of our new technology, the Company will need an operational model from generator to service at a customer's location to provide increased and operational visibility across all monitoring, control, and dispatch functions involving the electric grid. Current and future deployment of automation is a key driver in creating a centralized group that has a system view and can manage the automation in a safe and effective manner. The advancement of systems and automation devices in the field has removed the need for controllers and dispatchers to have institutional knowledge of the area they are managing. Therefore, the industry is moving to consolidated and centralized centers focused on using controllable devices, and the benefits of these devices are maximized in a centralized environment.

A UCC will support improvement in optimizing restoration efforts, particularly during the most impactful events. A UCC will support the Company's operation in extreme conditions with the use of an EOC to assist in a holistic service restoration response for the communities Consumers Energy serves across its service territory. The Company is also considering including gas operations within the UCC concept.

Q. What operational benefits would be gained?

A. Distribution control center operators are transitioning from mostly manual, paper-driven processes to computer-assisted decision support systems that help manage the dynamic operating environment and the growing array of intelligent field devices and information sources being placed on the network.

The UCC concept provides a structure to support standard process, procedures, tools, and best practices across all operations and support organizations. While the transmission and HVD centers and DCCs have unified procedures using standard document change processes, the dispatch centers and other organizations maintain independent procedures. A UCC allows for all procedures to be brought under a common repository with a standard document change process, which would improve the procedure revision and review process and create additional process cohesion between organizations.

The UCC will also provide uniformity in the tools used by operations and support groups. This has the potential to reduce duplicate tools and enhance existing tools to be used across multiple organizations, including systems that use common centralized infrastructure. Standardization of switching order generation tools, switching order administration tools, and logging tools in the system operation and dispatch areas would help to promote efficiencies and coordination between these operational organizations.

Sharing with all employees in a UCC will allow training processes and standardization to be more consistent and easier to schedule and deliver. Current HVD methodologies are industry standard and meet NERC compliance standards for training on the Bulk Electric System. These training processes and practices can be expanded to the LVD dispatchers to improve the safety and performance of operations on the LVD system. Training and job specific certification can also be expanded to support function employees to improve the performance of operations.

Utilities are moving to a single control center for very large areas in support of these advantages:

- The culture of operations can be consistent;
- Most weather events do not impact all the areas supported which allows control center resources to be quickly reallocated;
- Management and support staffs can be smaller with the same coverage and impact and can be more specialized;
- Exposure of individuals to multiple experts occurs without effort; and
- Connectivity with business continuity and ICS process application.

A UCC will also offer the opportunity for work force optimization. This supports a common progression path for succession, work forces needed, and career advancement. In addition, work groups will be available to cover other workload needs during unique events and the storm restoration process, which is currently limited by separated centers.

Q. Please describe any benchmarking efforts supporting a UCC.

A. Consumers Energy has reached out to other utilities involving approaches to conduct monitoring and control functions and establishing a control center of the future, including Oklahoma Gas & Electric, Pacific Gas & Electric, Duke Energy, and Louisville Gas & Electric. Such input informed the Company's proposal for a consolidated electric control center for control room operations.

Consumers Energy has also engaged Mosaic Company ("Mosaic") to provide professional services for the Advanced Distribution Management System ("ADMS") project. Mosaic has utility distribution control center experience with clients such as Arizona Public Service, Xcel Energy, Puget Sound Energy, and others. Mosaic recommended that Consumers Energy move fully to a centrally managed, control center-directed model. Combining control room operations will reduce jurisdictional overlap on controllers and dispatchers and improve role alignment, efficiencies, and best use of the new ADMS tools.

Consumers Energy has also engaged with the Electric Power Research Institute ("EPRI") and its materials, which further recognize that added technology and automation support the need for consolidation with a scalable, adaptable, and flexible utilization of resources and applications.[1] For example, Consumers Energy is participating in EPRI's DCC Modernization Project as part of its benchmarking research, which is gathering information from various utilities on this subject and is slated for completion of a technical report in 2020.

These benchmarking efforts have indicated that Consumers Energy's control center facilities are lagging when compared with others in the industry.

Q. Please summarize why the UCC is needed?

A. The current operational centers pose several limitations which the UCC will address. Failing to address these limitations presents risks in Consumers Energy operating the system and serving its customers:

- Space limitations and outdated facilities. Consumers Energy's electric SCC controllers, DCC controllers, and Work Management Center dispatch personnel are currently physically separated, and their primary method of interaction is through repeated phone calls to share information and collaborate on

[1] See EPRI Program on Technology Innovation:Future Control Centers 2005 (pg 6-3, 10-1, 10-2) https://www.epri.com/#/pages/product/000000000001012307/?lang=en-US; Functional Requirements of Next Generation Control Center Applications 2011 (pg. 1-7, 101, 6-1, 6-2) https://www.epri.com/#/pages/product/000000000001020058/?lang=en-US.

dispatching field resources. The current centers do not have enough space to achieve the co-location of these resources that manage the system and dispatch field personnel to resolve operational issues. Also, these facilities are out of date and require maintenance which impacts the ability to operate the systems. Some facilities lack the redundancy in mechanical and electrical systems that is necessary to ensure continued operations in the event of a crisis. The expansion of technological tools is also expanding data and security requirements, some within a required six wall boundary pursuant to NERC/Federal Energy Regulatory Commission requirements, and all needing proper infrastructure expansion to support operations. The co-location of control centers and dispatch personnel and associated infrastructure will improve the speed at which issues can be addressed and how electric service can be restored.

- Future Electric Supply and Distributed Resources Impact. The Company anticipates that the energy environment will change to include electric supply functions on the 46 kV and LVD distribution systems where growth in integrated and distributed resources continues to expand. Including the Merchant Operations as part of the UCC will address the electric supply changes as the energy landscape changes and operational impacts are realized.
- Outdated technology. The current control centers use outdated electronic displays of the transmission, sub-transmission, and distribution network compared with what is now common in the industry. This limits situational awareness, which is always critical, but particularly important during periods

of crisis (for example, during large storms). The lack of modern technology and facilities also limits training opportunities.

- Simplified Common Paths. The consolidation of operations at the current SCC, DCC, and LVD Dispatch Centers, including support organizations such as Operations Engineering, Smart Energy Operations, Grid Applications, and Restoration Management, will allow for centralized processes, procedures, training, and certification throughout these operations and support organizations.
- Standard Work. The UCC concept provides a structure to support standard process, procedures, tools, and best practices across all operations and support organizations.
- Training processes and standardization will be easier to schedule, deliver, and build consistency by sharing with all employees in a UCC. The current Company Transmission and HVD training methodologies, which meet NERC compliance and industry standards, can be expanded to the LVD Dispatchers to improve the safety and performance of operations on the LVD system. Training and job specific certification can also be expanded to associated support functions employees to improve the performance of operations.
- The UCC concept will provide a structure and a single plan for continued reliable system operations, merchant, and support functions in the event of an incident that threatens to disrupt these functions. Currently, multiple plans exist for the operational recovery of the electric operations organizations and support

functions. A single coordinated process across these organizations will improve overall response and reduce duplication of resources.

- Monitoring and managing the network of remotely controlled field devices from dispatch and control centers is critical for grid operations. As part of the UCC Project, the Company will streamline the ability to monitor the reliability and performance of remote devices to a consolidated Network Operations Center.
- EOC and ICS Impact. The combined operation in a UCC will support the continued use and evolution of the ICS structure, tools, and practices, including Company-wide coordination of events affecting the customers across Michigan and surrounding states.

Q. What is the projected timeline for development of the UCC Project?

A. To complete concept scope and the initial framework for configuring the facility, infrastructure, security, design criteria, and hardened requirements to support the UCC is expected to be completed in 2020, followed by the following projected timeline:

- Facility requirement plans for property site selection and acquisition for the UCC is planned for 2021.
- Property detailing and base utilities infrastructure preparation along with design completion and contractor and vendor selection is planned for 2021.
- Construction is planned to begin in 2022 and be completed by 2023.
- Occupancy is targeted to begin in January 2024.
- The alternate/back-up locations refresh is scheduled to be completed by the end of 2025.

Q. What is the projected cost related to the UCC included in this case?

A. In this case, the Company is projecting $1 million to complete concept scope, the facility site requirements, and property selection and acquisition in 2021. This amount is included in Company witness Saba's Exhibit A-94 (LDS-3).

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

SCOTT A. HUGO

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

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

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director, Generation Asset Strategy.

<u>Qualifications</u>

Q. Please describe your educational background.

A. In 1995, I received a Bachelor of Science in Electrical Engineering from Michigan State University.

Q. Please describe your business experience.

A. From 1995 to 1996, I was employed by Detroit Diesel as a Maintenance Engineer. In August 1996, I accepted the position of Controls Design Engineer with NEWCOR Bay City and progressed to Senior Controls Design Engineer in 1997. In January 2003, I accepted a position as a system engineer with Consumers Energy at the D.E. Karn ("Karn")/J.C. Weadock ("Weadock") Generating Complex. My responsibilities as a system engineer at the Karn/Weadock Generating Complex included monitoring the health, troubleshooting, planning routine maintenance, and creating long range plans for the electric and fuel handling systems for Karn Units 1 and 2. In 2007, I was promoted to Strategic Planning Economic Based Reliability Lead and had responsibility for gathering, reviewing, calculating economic benefit when required, and prioritizing Capital Expenditure and Major Maintenance projects for the Karn/Weadock site. In this position, I worked with Operations and Engineering to prioritize the work identified at the site and represent the site's interest at the Generation level, in addition to other Generation sites' requests. In May 2012, I accepted the position as the East Side Engineering Services Department Plant Modification Section Head. In September 2015, I accepted the position of Karn/Weadock Production Manager. In February 2017, I accepted the position of Manager of Generation Asset Strategy. In October 2018, I was promoted to Director, Generation Asset Strategy, the position I currently hold. In this role I am responsible for the strategy for the Company's coal, oil- and gas-fired, hydroelectric, and renewable generation assets, as well as the management of those assets.

Q. What has been your involvement in previous proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. I have provided witness support in the Company's 2018 Integrated Resource Plan ("IRP") under MCL 460.6t in Case No. U-20165 and the Company's 2018 Electric Rate Case No. U-20134.

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. Towards that end I will:

- Describe Consumers Energy's coal-, 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: (1) focus continued investment in those generating units (J.H. Campbell ("Campbell") 3, Zeeland, and Jackson Generating Station ("Jackson")) which provide the most economic benefit for our customers; and (2) sustain safe and environmentally compliant operations for its Medium 4 coal units (Campbell Units 1 and 2 and Karn Units 1 and 2) through their retirement dates;
- Support the periodic outage plans and the Generation Unit Availability and Random Outage Rate ("ROR") projections for coal generation, oil- and

gas-fired peaking generation, and hydroelectric power generation, for the projected test year ending December 31, 2021;

- Support the reasonableness and prudence of the capital expenditures for coal generation, oil- and gas-fired peaking generation, and hydroelectric power generation for the historical test year ended December 31, 2018, the bridge period beginning January 1, 2019 and ending December 31, 2020, and the projected test year ending December 31, 2021;

- Support the reasonableness and prudence of the projected investment for Company-owned Solar Generation for the bridge year ending December 31, 2020, and the projected test year ending December 31, 2021;

- Support the reasonableness and prudence of the Operation and Maintenance ("O&M") and fuel handling expenses for coal generation, oil- and gas-fired peaking generation, and hydroelectric power generation for the historical test year ended December 31, 2018, the bridge period beginning January 1, 2019 and ending December 31, 2020, and the projected test year ending December 31, 2021;

- Support the reasonableness and prudence of the O&M expenses for the Karn Units 1 and 2 retention and separation incentives for the bridge period beginning January 1, 2019 and ending December 31, 2020, and the projected test year ending December 31, 2021;

- Support the avoidable and incremental capital expenditures and O&M Major Maintenance expenses for the projected test year ending December 31, 2021, under the 2024 early retirement scenarios for the Company's Campbell Unit 1, Campbell Unit 2, and Campbell Units 1 and 2; and

- Support the avoidable and incremental capital expenditures and O&M Major Maintenance expenses for the projected test year ending December 31, 2021, under the 2025 early retirement scenarios for the Company's Campbell Unit 1, Campbell Unit 2, and Campbell Units 1 and 2.

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

A. Company witness Keith G. Troyer's testimony supports the Power Supply Cost Recovery ("PSCR") costs planned to be incurred, taking into account the periodic outages identified in Exhibit A-67 (SAH-1) and the generating unit availability projections in Exhibit A-68 (SAH-2). Company witness Troyer also supports the competitive solicitation process and timeline associated with the IRP solar initiative investment and the capacity value of the Company's generation assets in the Midcontinent Independent System Operator's ("MISO") Planning Resource Auction ("PRA") in my Exhibit A-12 (SAH-3), Schedule B-5.2.

Company witness Heidi J. Myers' testimony discusses the accounting treatment for any required investment in the IRP solar initiative prior to the end of the projected test period ending December 31, 2021.

Company witness Heather A. Breining's testimony supports the Company's strategy for complying with environmental regulations and related Air Quality, Resource Conservation Recovery Act, Steam Electric Effluent Guidelines ("SEEG"), and Clean Water Act Section 316(b) expenditures, as found in my Exhibit A-69 (SAH-4).

Finally, Company witness Daniel L. Harry's testimony supports deferred accounting treatment for the Karn Units 1 and 2 retention and separation expenses that I will discuss later in this direct testimony, and which are reflected in my Exhibit A-70 (SAH-5), page 1.

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

A. Yes, I am sponsoring the following exhibits:

Exhibit A-67 (SAH-1)		Major Outages, Fossil Generation and Ludington;
Exhibit A-68 (SAH-2)		Generating Unit Availability Projections;
Exhibit A-12 (SAH-3)	Schedule B-5.2	Generation Capital Expenditures;
Exhibit A-69 (SAH-4)		Generation Capital Expenditures—Avoidable and Incremental Under Campbell 1 & 2 Early Retirement Scenarios;

Exhibit A-70 (SAH-5)	Generation Operation and Maintenance Expenses; and
Exhibit A-71 (SAH-6)	Generation O&M Major Maintenance Expenses—Avoidable Under Campbell 1 & 2 Early Retirement Scenarios.

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

A. Yes.

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

A. My direct testimony is divided into three sections. Section I will present exhibits and supporting testimony on the Company's generating assets, its generating asset strategy, and projected performance metrics considering the Company's MPSC-approved IRP. Section II will present exhibits and supporting testimony for the historical and projected generation capital expenditures. This section will include an evaluation of the avoidable and incremental capital expenditures associated with various early retirement scenarios for Campbell Units 1 and 2 in 2024 and 2025. Section III will present exhibits and supporting testimony for the historical and projected generation O&M expense. This section will include support of the reasonableness and prudence of the O&M expenses for the Karn Units 1 and 2 retention and separation incentives and an evaluation of the avoidable major maintenance expenses associated with various early retirement scenarios for Campbell Units 1 and 2 in 2024 and 2025.

SECTION I

GENERATION ASSETS

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

A. As of December 4, 2019, the Company's total owned generation assets had a net demonstrated summer operating capability of 5,888 MW, comprised of the following units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	RETIREMENT DATE	NET GENERATING CAPABILITY (MW)
COAL FIRED				
JH Campbell 1	West Olive, MI	1962	2031	260
JH Campbell 2	West Olive, MI	1967	2031	333
JH Campbell 3	West Olive, MI	1980	2040	785 (owned share)
DE Karn 1	Essexville, MI	1959	2023	255
DE Karn 2	Essexville, MI	1961	2023	253
OIL OR GAS FIRED				
DE Karn 3	Essexville, MI	1975	2031	593
DE Karn 4	Essexville, MI	1977	2031	465
Zeeland CC	Zeeland, MI	2002	2041	534
Zeeland 1A	Zeeland, MI	2002	2041	160
Zeeland 1B	Zeeland, MI	2002	2041	159
Jackson	Jackson, MI	2002	2041	541
HYDROELECTRIC				
Alcona	Alcona County, MI	1924	n/a	3
Allegan	Allegan County, MI	1936	n/a	1
Cooke	Iosco County, MI	1911	n/a	7
Croton	Newaygo County, MI	1907	n/a	3
Five Channels	Iosco County, MI	1912	n/a	6
Foote	Iosco County, MI	1918	n/a	3
Hardy	Newaygo County, MI	1931	n/a	33
Hodenpyl	Wexford County, MI	1925	n/a	5
Loud	Iosco County, MI	1913	n/a	5
Mio	Oscoda County, MI	1916	n/a	2
Rogers	Mecosta County, MI	1906	n/a	2
Tippy	Manistee County, MI	1918	n/a	6
Webber	Ionia County, MI	1907	n/a	0
RENEWABLES				
Lake Winds	Mason County, MI	2012	2043	101
Cross Winds (Phase I)	Tuscola County, MI	2014	2045	111
Cross Winds (Phase II)	Tuscola County, MI	2018	2049	44
Cross Winds (Phase III)	Tuscola County, MI	2018	2049	76
Solar Gardens- GVSU	Grand Rapids, MI	2016	2041	3
Solar Gardens- WMU	Kalamazoo, MI	2016	2041	1
ENERGY STORAGE				
Ludington Units 1-6	Ludington, MI	1973	2069	1138 (owned share)

Q. What does "owned share" mean when used with respect to Campbell Unit 3?

A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the 785 MW capacity reported is 93% of the Campbell Unit 3 net demonstrated summer operating capability, reflecting the Company's share of ownership.

Q. What does "owned share" mean when used with respect to Ludington Pumped Storage Plant ("Ludington" or the "Ludington Plant") Units 1-6?

A. The Company owns 51% of the Ludington Plant and DTE Electric Company owns the remaining 49%. Thus, the 1138 MW capacity reported is 51% of the total Ludington Plant net demonstrated summer operating capability, reflecting the Company's share of ownership.

<u>GENERATION ASSET STRATEGY</u>

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

A. The Company's generation asset strategy is focused on providing safe, reliable, regulatory compliant and economic energy and capacity for its customers. This strategy will be implemented within the construct of the Company's clean energy goals and its MPSC-approved IRP.

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

A. Consistent with our strategy, the Company's generating asset investments will focus on those generating assets that provide the most economic benefit to customers through their energy and capacity value in the respective MISO markets. During 2018 alone, approximately 53% of the energy value and 45% of the capacity value realized by the

Consumers Energy generating fleet was realized from Campbell Unit 3 and the Zeeland units. When the Jackson combined cycle units are included in the mix, the 2018 energy value is approximately 66% of the total energy value provided by all of Consumers Energy's generating units. As such, the Company's investment focus and associated performance projections, have been aggressively set for these generating units.

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

A. The Company's generation asset strategy with respect to the remaining generating units will vary depending on each unit's energy value, capacity value and, consistent with the Company's currently approved IRP, expected retirement date. In each and every case the Company will continue to maintain the units to ensure safe and environmentally compliant operations. I will provide additional detail regarding the Company's generation asset strategy for each of the generating units or group of generating units in this testimony describing projected generating unit availability.

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

Q. Please describe Exhibit A-67 (SAH-1).

A. Exhibit A-67 (SAH-1) identifies the major outages (28 days or longer in duration) that are scheduled during the Projected Test Year ending December 31, 2021, 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 reflected on Exhibit A-68 (SAH-2).

Q. Please describe Exhibit A-68 (SAH-2), Generating Unit Availability Projections.

A. Exhibit A-68 (SAH-2) details Generating Unit Availability Projections for Consumers Energy's coal generation, peaking generation, and hydraulic power generation for the projected test year beginning January 1, 2021 and ending December 31, 2021. 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 Periodic Factor 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.

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

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

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

A. The ROR projections for the projected test year ending December 31, 2021 were developed from the five-year (2014-2018) average. These five-year averages were then adjusted to reflect current operating conditions and projected unit investment. The projected unit investment is developed in accordance with the Company's generation asset strategy. These five-year historical ROR average values are presented in Exhibit A-68 (SAH-2), column (b).

Q. Please define Periodic Factor ("PF").

A. PF is a measure of the percent of lost availability that results from planned outages, planned outage extensions, planned de-rates and planned de-rate extensions. Planned de-rates can be taken for a variety of reasons, including the performance of necessary maintenance work which does not require an outage to perform, or the combustion of a coal blend with a lower heat content than is required to achieve the net demonstrated capability of the unit.

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

A. Consistent with the Company's generation asset strategy, the Company schedules planned generating unit outages during periods in which the margin between the generating unit production cost and the projected MISO energy market price is lowest. This strategy results in creating greater NEV as I will discuss in more detail later in this direct testimony. In general, the projected MISO energy market pricing is lower in the shoulder months of spring and fall due to historically lower demand.

Q. Does this outage scheduling strategy apply to all of the Company's generating units?

A. No. For those generating units which have higher production costs and, as a result, are less likely to be dispatched, the available window for scheduling generating unit outages is much larger. The specific strategy for each generating unit or category of generating units will be discussed in more detail later in this testimony.

Q. Please define Projected Availability.

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

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

A. The Projected Availability for each generating unit or category of generating unit is a simple combination of the periodic factor and the projected ROR. Projected Availability is the key performance metric for implementation of the Company's generation asset strategy for each generating unit or category of generating unit.

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

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

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

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

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

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

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

A. An improvement in Availability can translate to a customer benefit in several ways. The immediate benefit is that the generating unit or the category of generating unit is available for dispatch for a greater number of hours throughout the year, likely leading to increased generation, and consequently higher NEV, on an annual basis.

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

A. The Company utilizes NEV to quantify this customer benefit. At a high level, NEV of a generating unit is the difference between the market value of energy and the cost of producing and supplying that energy. NEV is the net customer benefit of a generator's energy production expressed in dollars. These values are presented in Exhibit A-68 (SAH-2), column (f), which identifies five-year (2014-2018) actual NEV amounts.

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

A. Typically, economic investments that improve the reliability and availability of the generating unit or category of unit will result in increasing NEV. Economic investments that result in a reduction in the cost to generate will also result in increasing NEV, all else being equal. Positive NEV increases when a generating unit operates more frequently during periods in which market pricing exceeds the cost of production for that unit. Historically, market pricing has tended to be higher in the summer and winter, although there is variability to market conditions. As discussed earlier in my testimony, this is the reason that periodic outages are generally scheduled in the shoulder months of spring and fall. Market prices are typically lower during this time period, thereby reducing the PSCR impact of each scheduled outage.

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

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

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

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

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

A. In addition to measuring NEV for a generating unit, the Company also considers the impact a higher availability (specifically ROR) will have on the amount of capacity available from a particular generating unit which receives a monetary credit in the MISO Resource Adequacy Market. Table 2 below summarizes the capacity value of the Company's generating units in the 2019-2020 PRA for Zone 7. Company witness Troyer discusses the capacity value of the Company's generating units in the PRA, in his 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	NET GENERATING CAPABILITY (MW)	MISO CAPACITY CREDITS (ZRCs)	CAPACITY VALUE ZONE 7 (SETTLEMENT)	CAPACITY VALUE ZONE 7 (CONE)
COAL FIRED				
JH Campbell 1	260	251	$ 2,226,245	$ 22,296,343
JH Campbell 2	333	304	$ 2,696,328	$ 27,004,335
JH Campbell 3	785 (owned share)	757	$ 6,714,212	$ 67,244,348
DE Karn 1	255	223	$ 1,977,899	$ 19,809,101
DE Karn 2	253	226	$ 2,004,507	$ 20,075,591
OIL OR GAS FIRED				
DE Karn 3	593	478	$ 4,239,621	$ 42,460,764
DE Karn 4	465	272	$ 2,412,504	$ 24,161,774
Zeeland CC	534	524	$ 4,647,618	$ 46,546,946
Zeeland 1A	160	158	$ 1,401,381	$ 14,035,148
Zeeland 1B	159	155	$ 1,374,773	$ 13,768,658
Jackson	541	532	$ 4,718,574	$ 47,257,587
HYDROELECTRIC				
Alcona	3	3	$ 26,609	$ 266,490
Allegan	1	1	$ 8,870	$ 88,830
Cooke	7	6	$ 53,217	$ 532,980
Croton	3	3	$ 26,609	$ 266,490
Five Channels	6	6	$ 53,217	$ 532,980
Foote	3	3	$ 26,609	$ 266,490
Hardy	33	31	$ 274,955	$ 2,753,732
Hodenpyl	5	5	$ 44,348	$ 444,150
Loud	5	4	$ 35,478	$ 355,320
Mio	2	2	$ 17,739	$ 177,660
Rogers	2	2	$ 17,739	$ 177,660
Tippy	6	6	$ 53,217	$ 532,980
Webber	0	0	$ -	$ -
RENEWABLES				
Lake Winds	101	18	$ 159,651	$ 1,598,941
Cross Winds (Phase I)	111	21	$ 186,260	$ 1,865,431
Cross Winds (Phase II)	44	8	$ 70,956	$ 710,640
Cross Winds (Phase III)	76	12	$ 106,434	$ 1,065,961
Solar Gardens- GVSU	3	2	$ 17,739	$ 177,660
Solar Gardens- WMU	1	1	$ 8,870	$ 88,830
ENERGY STORAGE				
Ludington Units 1-6	1138 (owned share)	1085	$ 9,623,408	$ 96,380,604

Q. Please provide an overview of the generation asset strategy for Campbell Units 1 and 2.

A. The strategic plan for Campbell Units 1 and 2 is predicated on their current planned retirement in May of 2031 as documented in the approved IRP. The overall long-term objective for Campbell Units 1 and 2 is to maintain economic dispatch from the customer's perspective. The capital and major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be considered only if they provide significant value to customers.

Q. How will the Company's generation asset strategy for Campbell Units 1 and 2 impact their projected performance?

A. It is anticipated that unit performance will degrade slightly from current performance. Based upon the Campbell Units 1 and 2 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 23% at Campbell Unit 1 and 22% at Campbell Unit 2 in 2021, as shown on Exhibit A-68 (SAH-2), lines 1 and 2, column (c). During the five-year historical period from 2014 through 2018, Campbell Unit 1 had an ROR of 11.81% and Campbell Unit 2 had an ROR of 13.75% as shown on Exhibit A-68 (SAH-2), lines 1 and 2, column (b).

Q. How is this strategy reflected in the projected availability for Campbell Units 1 and 2 in 2021?

A. The Projected Availabilities for Campbell Units 1 and 2 in 2021 are 64.13% and 50.03% respectively, as shown on Exhibit A-68 (SAH-2), lines 1 and 2, column (e). The availability for Campbell Unit 1 reflects a projected ROR of 23% and a PF of 16.72%, as shown on Exhibit A-68 (SAH-2), line 1, columns (c) and (d). The planned Campbell Unit 1 outage for 2021 is scheduled to begin on September 24, 2021 and last for 45 days, as reflected on Exhibit A-67 (SAH-1), line 11. The Availability for Campbell Unit 2 reflects a projected ROR of 22% and a PF of 35.86%, as shown on Exhibit A-68 (SAH-2), line 2, columns (c) and (d). The planned Campbell Unit 2 outage for 2021 is scheduled to begin on March 19, 2021 and last for 60 days, as reflected on Exhibit A-67 (SAH-1), line 1. These outages are scheduled during periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers.

Q. How does the Campbell Units 1 and 2 unit availability translate into customer value?

A. As reflected on Exhibit A-68 (SAH-2), lines 1 and 2, column (f), during the five-year historical period from 2014 through 2018, Campbell Unit 1 had a NEV of $53.0 million and Campbell Unit 2 had a NEV of $58.5 million. The 2018 NEV for each of these units was $8.50 million and $9.13 million for Campbell Units 1 and 2, respectively.

Q. Please quantify the capacity value for Campbell Units 1 and 2?

A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in the 2019-2020 PRA is $2.23 million for Campbell Unit 1 and $2.70 million for Campbell Unit 2. The hypothetical capacity value based upon Cost of New Entry ("CONE") for Zone 7 in the 2019-2020 PRA is $22.30 million for Campbell Unit 1 and $27.00 million for Campbell Unit 2

Q. Please provide an overview of the generation asset strategy for Campbell Unit 3.

A. The strategic plan for Campbell 3 is predicated on its current planned retirement in 2040 as documented in the approved IRP. The overall long-term objective for Campbell Unit 3 is to maintain economic dispatch from the customer's perspective. The unit provides significant value to customers in both the energy and resource adequacy markets. The capital and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available are included in the plan. Projects that are targeted to improve reliability will be included in the plan if they provide value to customers.

Q. How will the Company's generation asset strategy for Campbell Unit 3 impact its projected performance?

A. It is anticipated that unit performance will remain relatively consistent with current performance. Based upon the Campbell Unit 3 capital and major maintenance projects discussed later in this testimony, the Company's generation asset strategy is expected to result in an ROR of 5% at Campbell Unit 3 in 2021, as shown on Exhibit A-68 (SAH-2), line 3, column (c). During the five-year historical period from 2014 through 2018, Campbell Unit 3 had an actual ROR of 7.32%, as shown on Exhibit A-68 (SAH-2), line 3, column (b).

Q. How is this strategy reflected in the projected availability for Campbell Unit 3 in 2021?

A. The Projected Availability for Campbell Unit 3 in 2021 is 85.87%, as shown on Exhibit A-68 (SAH-2), line 3, column (e). This Availability for Campbell Unit 3 reflects a projected ROR of 5% and a PF of 9.61%, as shown on Exhibit A-68 (SAH-2), line 3, columns (c) and (d). The planned outage for 2021 is scheduled to begin on April 3, 2021 and last for 35 days, as reflected on Exhibit A-67 (SAH-1), line 3. The outage is scheduled during a period in which energy prices are projected to be lower, thereby reducing the impact of the outage on customers.

Q. How does the Campbell Unit 3 Availability translate into customer value?

A. As reflected on Exhibit A-68 (SAH-2), line 3, column (f), during the five-year historical period from 2014 through 2018, Campbell Unit 3 had a NEV of $228.5 million. The 2018 NEV for Campbell Unit 3 was $47.3 million.

Q. Please quantify the capacity value for Campbell Unit 3?

A. As reflected in Table 2, the Campbell Unit 3 capacity value based upon the settlement price for Zone 7 in the 2019-2020 PRA is $6.71 million and the Campbell Unit 3 hypothetical capacity value based upon CONE for Zone 7 in the 2019-2020 PRA is $67.24 million.

Q. Please provide an overview of the generation asset strategy for Karn Units 1 and 2.

A. The strategic plan for Karn Units 1 and 2 is predicated on their current planned retirement in May of 2023 as documented in the approved IRP. The overall remaining life objective for Karn Units 1 and 2 is to maintain economic dispatch and capacity value from the customer's perspective. The capital and major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will not be considered.

Q. How will the Company's generation asset strategy for Karn Units 1 and 2 impact their projected performance?

A. It is anticipated that the unit performance will degrade from current performance for both Karn Units 1 and 2, and this risk will be accepted to limit new investment as the units near retirement. Based upon the Karn Units 1 and 2 capital and major maintenance projects discussed later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 42% at Karn Unit 1 and 27% at Karn Unit 2 in 2021, as shown on Exhibit A-68 (SAH-2), lines 4 and 5, column (c). During the five-year historical period from 2014 through 2018, Karn Unit 1 had an ROR of 25.03% and Karn Unit 2 had an ROR of 13.49%, as shown on Exhibit A-68 (SAH-2), lines 4 and 5, column (b).

Q. How is this strategy reflected in the Projected Availability for Karn Units 1 and 2 in 2021?

A. The Projected Availabilities for Karn Units 1 and 2 in 2021 are 45.79% and 59.55%, respectively, as shown on Exhibit A-68 (SAH-2), lines 4 and 5, column (e). The Availability for Karn Unit 1 reflects a projected ROR of 42% and a PF of 21.06%, as shown on Exhibit A-68 (SAH-2), line 4, columns (c) and (d). The planned Karn Unit 1 outage for 2021 is scheduled to begin on October 8, 2021 and last for 31 days, as reflected on Exhibit A-67 (SAH-1), line 13. The Availability for Karn Unit 2 reflects a projected ROR of 27% and a PF of 18.43%, as shown on Exhibit A-68 (SAH-2), line 5, columns (c) and (d). The planned Karn Unit 2 outage for 2021 is scheduled to begin on October 21, 2021 and last for 28 days, as reflected on Exhibit A-67 (SAH-1), line 14. These outages are scheduled during periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers.

Q. How does the Karn Units 1 and 2 unit availability translate into customer value?

A. As reflected on Exhibit A-68 (SAH-2), lines 4 and 5, column (f), during the five-year historical period from 2014 through 2018, Karn Unit 1 had a NEV of $42.5 million and Karn Unit 2 had a NEV of $44.0 million. The 2018 NEV for each of these units was $7.24 million and $6.49 million for Karn Units 1 and 2, respectively.

Q. Please quantify the capacity value for Karn Units 1 and 2.

A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in the 2019-2020 PRA is $1.98 million for Karn Unit 1 and $2.00 million for Karn Unit 2. The hypothetical capacity value based upon CONE for Zone 7 in the 2019-2020 PRA is $19.81 million for Karn Unit 1 and $20.08 million for Karn Unit 2.

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 retirement in May of 2031 as documented in the approved IRP. The value for these units resides primarily in the resource adequacy market. The overall long-term objective for Karn Units 3 and 4 is to maintain reliable reserve capacity for our customers. The capital and major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be considered if they provide significant value to customers.

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

A. It is anticipated that unit performance for Karn Units 3 and 4 will slightly degrade from current performance. Based upon the Karn Units 3 and 4 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 32% at Karn Unit 3 and 37% at Karn Unit 4 in 2021, as shown on Exhibit A-68 (SAH-2), lines 6 and 7, column (c). During the five-year historical period from 2014 through 2018, Karn Unit 3 had an ROR of 31.94%

and Karn Unit 2 had an ROR of 33.62%, as shown on Exhibit A-68 (SAH-2), lines 6 and 7, column (b).

Q. How is this strategy reflected in the projected availability for Karn Units 3 and 4 in 2021?

A. The projected availabilities for Karn Units 3 and 4 in 2021 are 55.09% and 55.04%, respectively, as shown on Exhibit A-68 (SAH-2), lines 6 and 7, column (e). The availability for Karn Unit 3 reflects a projected ROR of 32% and a PF of 18.99%, as shown on Exhibit A-68 (SAH-2), line 6, columns (c) and (d). The planned Karn Unit 3 outage for 2021 is scheduled to begin on October 1, 2021 and last for 69 days, as reflected on Exhibit A-67 (SAH-1), line 12. The availability for Karn Unit 4 reflects a projected ROR of 37% and a PF of 12.63%, as shown on Exhibit A-68 (SAH-2), line 7, columns (c) and (d). The planned Karn Unit 4 outage for 2021 is scheduled to begin on October 29, 2021 and last for 46 days, as reflected on Exhibit A-67 (SAH-1), line 15. These outages are scheduled during periods in which energy prices are projected to be lower than the production cost for Karn Units 3 and 4, thereby reducing the potential impact of the outages on customers.

Q. How does the Karn Units 3 and 4 unit availability translate into customer value?

A. As reflected on Exhibit A-68 (SAH-2), lines 6 and 7, column (f), during the five-year historical period from 2014 through 2018, Karn Unit 3 had a NEV of -$5.8 million and Karn Unit 4 had a NEV of -$11.1 million. The 2018 NEV for each of these units was -$1.71 million and -$1.14 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 for several reasons, including the need to conduct operator training, perform unit demonstration testing, and unit performance. Due to the production cost for the units, the units get dispatched far less than the Company's other generating assets, thus necessitating non-economic operation for training and testing. However, despite the fact that the NEVs are slightly negative, the units provide a significant amount of value in the form of relatively cheap capacity, which far outweighs the negative NEV values.

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 2019-2020 PRA is \$4.24 million for Karn Unit 3 and \$2.41 million for Karn Unit 4. The hypothetical capacity value based upon CONE for Zone 7 in the 2019-2020 PRA is \$42.46 million for Karn Unit 3 and \$24.16 million for Karn Unit 4.

Q. Does the Company have any projects for Karn Units 3 and 4 which will improve unit performance?

A. Yes. The Company's capital expenditures for Karn Unit 4 includes a project scheduled for 2020 to repair and retrofit the electro-hydraulic controls ("EHC") for the unit. As I will discuss later in this direct testimony, this project is expected to result in improved unit performance which is expected to translate to improved energy and capacity value for customer.

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

A. The strategic plan for Zeeland is predicated on site retirement in May of 2041. The overall long-term objective for Zeeland is to maintain economic dispatch from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets. The capital and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be included in the plan if they provide value to customers.

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

A. It is anticipated that site performance will remain relatively consistent with current performance. Based upon the Zeeland capital and major maintenance projects that I will discuss later in this testimony, the Company's generation asset strategy is expected to result in an ROR of 4.0% at Zeeland in 2021, as shown on Exhibit A-68 (SAH-2), lines 15 through 17, column (c). During the five-year historical period from 2014 through 2018, the Zeeland site had ROR values below 4.0% for all units, as shown on Exhibit A-68 (SAH-2), lines 15 through 17, column (b).

Q. How is this strategy reflected in the projected availability for Zeeland in 2021?

A. The projected availability for the combined cycle generating units at the Zeeland site in 2021 is 87.45%, as shown on Exhibit A-68 (SAH-2), line 15, column (e). The Zeeland combined cycle generating unit availability is based upon a projected ROR of 4.0% and a PF of 8.91%, as shown on Exhibit A-68 (SAH-2), line 15, columns (c) and (d). The projected availabilities for the simple cycle generating units at the Zeeland site in 2021 is 82.76% and 82.77%, respectively, as shown on Exhibit A-68 (SAH-2), lines 16 and 17, column (e). The Zeeland simple cycle generating unit availabilities are based upon projected RORs of 4.0% and PFs of 13.79% and 13.78% respectively, as shown on Exhibit A-68 (SAH-2), lines 16 and 17, columns (c) and (d). The planned outages for the Zeeland Units 1 and 2 in 2021 are scheduled to begin on September 15, 2021, and last for 40 days, as reflected on Exhibit A-67 (SAH-1), lines 9 and 10. The outage is scheduled during a period in which energy prices are projected to be lower, thereby reducing the impact of the outage on customers.

Q. How does the Zeeland unit availability translate into customer value?

A. As reflected on Exhibit A-68 (SAH-2), lines 15 through 17, column (f), during the five-year historical period from 2014 through 2018, the Zeeland units provided a total NEV of $113.3 million. The 2018 NEV for Zeeland was $26.22 million.

Q. Please quantify the capacity value for Zeeland.

A. As reflected in Table 2, the Zeeland capacity value based upon the settlement price for Zone 7 in the 2019-2020 PRA is $7.42 million and the Zeeland hypothetical capacity value based upon CONE for Zone 7 in the 2019-2020 PRA is $74.35 million.

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

A. The strategic plan for Jackson is predicated on site retirement in May of 2041 as documented in the approved IRP. The overall long-term objective for Jackson is to maintain economic dispatch from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets. The capital and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be included in the plan if they provide value to customers.

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

A. It is anticipated that site performance will remain relatively consistent with current performance. Based upon the Jackson 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 6.30% at Jackson in 2021, as shown on Exhibit A-68 (SAH-2), line 18, column (c). Since the acquisition of Jackson in December 2015 through 2018, the Jackson site had an ROR of 3.23% for all units, as shown on Exhibit A-68 (SAH-2), line 18, column (b).

Q. How is this strategy reflected in the projected availability for Jackson in 2021?

A. The projected availability for all of the generating units at the Jackson site in 2021 is 91.65%, as shown on Exhibit A-68 (SAH-2), line 18, column (e). The availability for the Jackson site reflects a projected ROR of 6.30% and a PF of 2.19%, as shown on Exhibit A-68 (SAH-2), line 18, columns (c) and (d). There are no major planned outages in excess of 28 days for the Jackson units in 2021, however a short nine-day outage is scheduled for 2021.

Q. How does the Jackson unit availability translate into customer value?

A. As reflected on Exhibit A-68 (SAH-2), line 18, column (f), during the period since the acquisition of Jackson in December 2015 through 2018, the Jackson units provided a total NEV of $40.2 million. The 2018 NEV for Jackson was $17.66 million.

Q. Please quantify the capacity value for Jackson.

A. As reflected in Table 2, the Jackson capacity value based upon the settlement price for Zone 7 in the 2019-2020 PRA is \$4.72 million and the Jackson hypothetical capacity value based upon CONE for Zone 7 in the 2019-2020 PRA is \$47.26 million.

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

A. The strategic plan for Hydro is predicated on operating the units for the foreseeable future. The value for these units resides in providing renewable energy and capacity within the Company's generating portfolio. The overall long-term objective for the Hydro units is to maintain safe and compliant hydro sites for our customers. The recent hydro events around the country, such as the Oroville Dam Spillway failure in 2017, have provoked the Federal Energy Regulatory Commission ("FERC") and the Hydro Industry to make changes to dam safety best practices nationwide. These changes have resulted in additional regulatory compliance required projects. The Company negotiates with the FERC to prioritize the actions required and the deadlines of each to provide public safety with cost effective solutions. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be considered if they provide significant value to customers.

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

A. It is anticipated that Hydro performance will remain relatively consistent with current performance. Based upon the Hydro 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 6.5% for the Hydro units in 2021, as shown on Exhibit A-68

(SAH-2), line 14, column (c). During the five-year historical period from 2014 through 2018, the Hydro units had an ROR of 6.73% for all units, as shown on Exhibit A-68 (SAH-2), line 14, column (b).

Q. How is this strategy reflected in the projected availability for Hydro in 2021?

A. The projected availability for all of the Hydro units in 2021 is 90.75%, as shown on Exhibit A-68 (SAH-2), line 14, column (e). The availability for the Hydro units reflects a projected ROR of 6.5% and a PF of 2.94%, as shown on Exhibit A-68 (SAH-2), line 14, columns (c) and (d). There are no major outages planned for the Hydro units in 2021.

Q. How does the Hydro unit availability translate into customer value?

A. As reflected on Exhibit A-68 (SAH-2), line 14, column (f), during the five-year historical period from 2014 through 2018, the Hydro units provided a total NEV of $47.0 million. The 2018 NEV for the Hydro units was $9.50 million.

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

A. As reflected in Table 2, the capacity value of the Hydro units based upon the settlement price for Zone 7 in the 2019-2020 PRA is $0.64 million and the Hydro unit hypothetical capacity value based upon CONE for Zone 7 in the 2019-2020 PRA is $6.40 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 value for these units resides primarily in the resource adequacy market with limited energy value. The overall long-term objective for Ludington is to maintain reliable reserve capacity for our customers. The capital and major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be considered if they provide significant value to customers.

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

A. It is anticipated that Ludington performance will remain relatively consistent with current performance. Based upon the Ludington capital and major maintenance projects that I will discuss later in this testimony, as well as the Ludington unit major overhauls performed over the past six years, the Company's generation asset strategy is expected to result in an ROR of 5.10% for the Ludington units in 2021, as shown on Exhibit A-68 (SAH-2), lines 8 through 13, column (c). During the five-year historical period from 2014 through 2018, the Ludington units had average ROR values ranging from 5.14% to 30.92%, as shown on Exhibit A-68 (SAH-2), lines 8 through 13, column (b).

Q. How is this strategy reflected in the projected availability for Ludington in 2021?

A. With the exception of Ludington Unit 4 which has a projected availability of 72.78%, the projected availabilities for all of the Ludington units in 2021 is 81.61%, as shown on Exhibit A-68 (SAH-2), lines 8 through 13, column (e). The availabilities for the Ludington generating units reflect a projected ROR of 5.10% and PFs of 14.00% for Ludington Units 1 through 3, 5, and 6 and 23.31% for Ludington Unit 4, as shown on Exhibit A-68 (SAH-2), lines 8 through 13, columns (c) and (d). The major planned outages for the Ludington Units 1 through 6 in 2021 are scheduled to begin on May 2, 2021 and last for 42 days, as reflected on Exhibit A-67 (SAH-1), lines 3 through 8. The outage is scheduled during a period in which the likelihood of Ludington unit dispatch is lower, thereby reducing the impact of the outage on customers.

Q. How does the Ludington unit availability translate into customer value?

A. As reflected on Exhibit A-68 (SAH-2), lines 8 through 13, column (f), during the five-year historical period from 2014 through 2018, the Ludington units provided a total NEV of $117.0 million. The 2018 NEV for Ludington was $8.59 million.

Q. Please quantify the capacity value for Ludington?

A. As reflected in Table 2, the Ludington capacity value based upon the settlement price for Zone 7 in the 2019-2020 PRA is $9.62 million and the Ludington hypothetical capacity value based upon CONE for Zone 7 in the 2019-2020 PRA is $96.38 million.

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

A. The Company's strategic plan for Renewable Energy Assets, both wind and solar, is entirely driven by the Company's MPSC-approved IRP. Consistent with the IRP, the strategy for the wind assets is to complete construction and have all wind assets in service by end of 2022. With respect to solar, the Company plans to add 1,200 MW of incremental solar energy through May 2024, as discussed in more detail later in this testimony. The overall investment objective for the Company-owned assets is to provide funding for projects as appropriate to maintain economic dispatch from the customer's perspective. The Company has an energy-based availability target of 89% for its renewable energy assets. The availability target considers those periods during which the wind is sufficient to produce energy. The capital and major maintenance expenses in the plan are targeted to maintain the designed performance level.

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

A. Similar to the Company's 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. Historically, the Company has not measured NEV for its owned renewable energy assets however it plans to do so beginning in 2020.

Q. Please quantify the capacity value for Renewable Energy.

A. As reflected in Table 2, the renewable asset capacity value based upon the settlement price for Zone 7 in the 2019-2020 PRA is $0.55 million and the renewable asset hypothetical capacity value based upon CONE for Zone 7 in the 2019-2020 PRA is $5.51 million.

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

A. I have included these hypothetical values to illustrate the potential settlement risk that exists in the MISO PRA. Company witness Troyer provides additional information regarding the capacity value of the Company's generation assets in MISO's PRA as well as the projected capacity margin in future years for Zone 7.

Q. Do any of the above-discussed proposed retirement dates differ from those supported in the Company's IRP?

A. Yes. The IRP reflected a retirement date of 2049 for Ludington versus a retirement date of 2069 for Ludington reflected in this proceeding. The change in the proposed retirement date for Ludington is based upon a July 1, 2019 FERC Order in Project No. 2680-113 which extended the Ludington operating license for a period of 50 years.

Section 15(e) of the Federal Power Act[1] provides that any new license issued shall be for a term that is not less than 30 years or more than 50 years. This license extension results in a 2069 retirement date for Ludington. The retirement date of 2049 was based upon the minimum license extension of 30 years.

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

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

SECTION II

GENERATION CAPITAL EXPENDITURES

OVERVIEW

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

A. The major drivers in the determination of generation capital expenditures are plant safety, compliance with regulations, and reliability. Consumers Energy's strategy for complying with environmental regulations is addressed in the direct testimony of Company witness Breining.

[1] 16 U.S.C. § 808(e) (2012).

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

A. This exhibit presents the capital expenditures for Generation, 2018 through the Projected Test Year - 12 months ending December 31, 2021. Exhibit A-12 (SAH-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, 2018, the Projected Bridge Year beginning January 1, 2019 and ending December 31, 2019, the Projected Bridge Year beginning January 1, 2020 and ending December 31, 2020, and the Projected Test Year beginning January 1, 2021 and ending December 31, 2021. This summary information is broken down by Steam Power Generation, Hydraulic Power Generation, Pumped Storage Generation, and Other Production Plant. Pages 2 and 3 of this exhibit capture the same Historical Year, Bridge Years, and Test Year Generation capital expenditures information, but is presented by generating sites and environmental categories. This information is further detailed by Contractor, Labor, Materials, Business Expenses, Contingency, and Other. Page 4 of this exhibit represents a summary of pages 2 and 3 of this exhibit. Page 5 of this exhibit provides a summary of Non-Environmental and All Other Environmental capital expenditures in the projected bridge year ending December 31, 2020 and the projected test year ending December 31, 2021. Finally, pages 6 through 9 of this exhibit identify the capital projects and associated expenditures that are greater than $1 million that contribute to the overall capital expenditures summarized on pages 1 through 5 of this exhibit. Specifically, page 6 of this exhibit presents capital projects for the Historical Period ended December 31, 2018; page 7 of this exhibit presents capital projects for the Projected Bridge Year beginning January 1, 2019 and ending December 31, 2019; page 8 of this exhibit presents capital projects for the Projected Bridge Year beginning January 1, 2020 and ending December 31, 2020; and page 9 of this exhibit presents capital projects for the Projected Test Year ending December 31, 2021.

Q. What level of capital spending does the Company request the Commission to incorporate into rates in this case?

A. The Company's rate relief request in this case reflects capital spending on projects for its generating plants of $175.704 million for the historical test period ended December 31, 2018 as shown on Exhibit A-12 (SAH-3), Schedule B-5.2, page 1, line 15, column (b); $174.044 million in the projected bridge year ending December 31, 2019 as shown on Exhibit A-12 (SAH-3), Schedule B-5.2, page 1, line 15, column (c); $119.646 million in the projected bridge year ending December 31, 2020 as shown on Exhibit A-12 (SAH-3), Schedule B-5.2, page 1, line 15, column (d); and $161.075 million in the projected test year ending December 31, 2021 as shown on Exhibit A-12 (SAH-3), Schedule B-5.2, page 1, line 15, column (f).

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

A. In evaluating capital investments, the Company's first priority is addressing safety, regulatory, and compliance related projects. These projects are considered a mandatory cost of doing business.

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

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

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

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

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

A. No. The Company only calculates IRRs or PVRs for economic projects. Projects required for regulatory, compliance, and/or continued operations are reviewed to assure that the project is cost effective and result from a reasonable evaluation of alternatives, but because the project must be done for compliance and continued operation, IRR or

PVR is not calculated. However, when evaluating project alternatives related to regulatory, compliance and/or continued operations, IRRs or PVRs may be used.

Q. How does the Company evaluate customer benefits associated with Generation-related capital investments?

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

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

A. The cause of each of the historical events impacting availability are evaluated and measured, and the actions necessary to avoid the same or similar events are considered for implementation. In many cases, the actions necessary to prevent the event from recurring are cost beneficial. The availability projections, including ROR, simply reflect our best estimate of the operational benefits of those corrective actions that have already been taken or are planned to be taken, through the projected test year ending December 31, 2021.

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

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

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

A. Yes. The Company often forecasts future actions and capital expenditures based on currently available information, many months before the work is completed. To provide some perspective, the outage schedule used in this case was approved in September 2019. A review of the outage schedule used in this case identifies 16 scheduled outages that begin in March 2021 (17 months after the schedule was approved) and run through December 31, 2021, 26 months later. During each of these 16 scheduled outages, Consumers Energy has scheduled a number of tasks to be performed. Because of the long lead times, the number of outages scheduled during the test year, and the fact that several different tasks will be performed during each outage, it is inevitable that some scheduled outages and forecast capital expenditures will change. However, the Company has a history of prudent capital investments in its generating facilities, which have been consistently supported by the Commission.

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

A. Yes. Some of the reasons are: contractor availability, parts availability, changes in regulations, design changes, outage scope changes, changes in unit condition, and spot market prices.

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

A. Yes. The 2020 outage schedule originally included an outage at Karn Unit 1 for removal of three layers of plugged/deactivated catalyst in the Selective Catalytic Reduction ("SCR") Reactor and installation of two new layers of catalyst. The catalyst is being replaced because it is at end of life. A condition assessment (compliance with Oxides of Nitrogen ("NO_X") emission rates) identified an immediate need to perform this environmental compliance work in the fall of 2019 and, as a result, the outage was pulled forward. Failure to complete this work in 2019 would have limited the operation of the unit. Based upon these circumstances, the acceleration of this work was both reasonable and prudent.

Q. Briefly explain the benefits associated with making this change.

A. The primary benefit realized from making this change is regulatory compliance with NO_x emission rates. Maintaining system equipment in accordance with the original equipment manufacturer ("OEM") recommendations is a requirement of the Environmental Protection Agency ("EPA") consent decree. Other benefits include heat rate improvement and reduced risk of derates due to NO_x emission compliance, and reduced consumption of aqueous ammonia as well as activated carbon, both of which result in reducing PSCR expense.

Q. Please describe how the Company determines its Generation projected capital expenditure amounts.

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

2018 HISTORICAL TEST YEAR CAPITAL EXPENDITURES

Q. How does the 2018 actual capital expenditure of $175.704 million compare to the amount of capital reflected in the settlement agreement in Case No. U-20134?

A. The actual capital expenditure amount of $175.704 was $3.107 million greater than the requested amount of $172.597 million. A compilation of the 2018 projects which had an actual capital expenditure amount greater than $1 million is presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 6.

Q. How does the compilation of capital projects on Exhibit A-12 (SAH-3), Schedule B-5.2, page 6, compare with the 2018 capital projects in Part III filing requirement 115 for Case No. U-20134?

A. A comparison of the projects on Exhibit A-12 (SAH-3), Schedule B-5.2, page 6, with the 2018 projects included in Part III filing requirement 115 for Case No. U-20134 reveals that there are 13 projects on Exhibit A-12 (SAH-3), Schedule B-5.2, page 6, which weren't included in the Part III filing requirement 115 for Case No. U-20134. In addition, there were 4 projects for 2018 that were included in the Part III filing requirement 115 for Case No. U-20134 that are not presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 6.

Q. Please discuss the 2018 capital projects that were included in the Part III filing requirement 115 for Case No. U-20134 that are not presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 6.

A. The disposition of these capital projects is below:

- Campbell Unit 2 secondary air heater ("SAH") basket and seal replacement. The implementation of this project was deferred to 2020 and 2021. The projected capital expenditures for this project are $0.500 million in 2020 and $2.425 million in 2021, as discussed later in this direct testimony;

- Campbell Unit 2 catalyst management. The implementation of this project was deferred from 2019 to 2021 to align with Campbell Unit 2 periodic outage schedules. The catalyst material purchase was initiated in 2018, and catalyst modules were received in 2019. The 2018 capital expenditure amount was $0.435 million, the 2019 projected capital expenditure is $0.408 million, and the projected capital expenditure amounts for 2020 and 2021 are $0.700 million and $1.500 million as discussed later in this testimony;

- Campbell Unit 3 Main Boiler Feed Pump ("BFP") 'B' pump barrel replacement. This project was begun in 2018 and was completed in the fall 2019 Campbell Unit 3 outage. The project had a capital expenditure of $0.3 million in 2018 and a projected capital expenditure of $0.790 million in 2019; and

- Rebuild of the Caulkins Bridge and Piers – The total project spend during 2018 was $0.263 million and the project was completed in 2018.

Q. Please discuss the 2018 capital projects that were not included in the Part III filing requirement 115 for Case No. U-20134 that are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 6.

A. The disposition of these capital projects is below:

- Campbell Units 1 and 2 Pigeon Lake Channel South Jetty ($1.182 million). This project was added to rebuild the shoreline. Over the summer of 2017, a portion of Pigeon Lake inner channel shoreline directly east of the south Lake Michigan jetty experienced significant erosion due to high water levels and several summer storms (wave impact). This erosion compromised the access road out to the jetty, prohibiting vehicle access. The project re-established road access out to the south jetty, thereby enabling maintenance activities on the navigation lights (federally required). The road is also utilized during channel dredging activities (dredging cannot be completed without), which occur every few years to ensure adequate supply of cooling water from Lake Michigan available to Campbell Units 1 and 2. As part of the project, a section of the bank was armored to prevent future erosion and carryover of sand into the channel area;

- Campbell Unit 3 High Pressure Feedwater Heater 7A replacement ($1.075 million). Due to multiple feedwater heater tube leaks in 2017, the replacement of Campbell Unit 3 High Pressure Feedwater Heater 7A was accelerated. The heater purchase was initiated in 2018, with heater installation during the 2019 outage at Campbell Unit 3;

- Campbell Unit 3 Spray Dry Absorber (PM2.5) ($2.029 million). The Campbell Unit 3 Spray Dry Absorber was installed in 2016 and began operation in 2017. The 2018 capital expenditure included resolution of remaining punch list items, finalizing as-built drawings, and completion of system performance testing;

- Campbell Site Commons Dust Conveying Line to Campbell Unit 3 bunkers ($1.213 million). The projected capital included in the last rate case was only $0.572 million. The scope of the project was the installation of an additional dust conveying line that can be used to transport coal dust from the fuel handling area dust collectors to the Campbell Unit 3 bunkers. Prior to the project implementation, the coal dust collected in the yard by the dust collectors was conveyed pneumatically to either the Unit 1 or Unit 2 coal bunkers. When this line and/or the bunkers were not available, this very fine dust had to be vacuumed out of the dust collector and dumped back on the coal pile. This created an environmental and safety hazard as this dust is fluid-like, cannot be contained, and creates black clouds of explosive concentrations. Clouds of coal dust leaving the site boundaries are a violation of our Renewable Operating Permit, specifically Rule 901 and subject us to enforcement by the Michigan Department of Environmental Quality ("MDEQ"), now the Michigan Department of Environment, Great Lakes, and Energy ("EGLE");

- Karn Unit 4 Breeching – boiler to stack ($1.074 million). The Karn Unit 4 Breeching from the boiler to the stack entry was under evaluation in 2017 when the 2018 rate case filing was being prepared. The initial work plan called for replacement of the Karn Unit 4 breeching insulation and lagging beginning in 2018, with completion in 2023. The 2017 evaluation determined that this work could be completed in multiple phases: the first phase would address the immediate safety concerns by securing the deteriorated lagging and preventing falling debris, and the second phase would replace the breeching insulation and lagging over the course of several years. The first phase of this work was completed in 2018, which increased the 2018 capital spend beyond the $1 million Rate Case Part III threshold;

- Zeeland Diaphragm Exchange Program ($1.710 million). This project was implemented during the 2018 combined cycle outage. During inspection the diaphragm was found damaged, was at end of life, and required replacement;

- Zeeland Steam turbine L0 bucket replacement ($2.880 million). Pursuant to Technical Information Letters 1846 and 1847, the steam turbine low pressure rotor L0 and L1 buckets had to be inspected for stress corrosion and finger/dovetail cracking and bucket erosion. Upon inspection of the rotor, it was determined that both L0 and L1 buckets required replacement; the L1 buckets were covered by the Long Term Service Agreement ("LTSA"), the L0 buckets were not. The steam turbine inspection was performed based upon the number of unit operating hours and the L0 bucket replacement was not anticipated;

- Zeeland base outage capital ($2.421 million). This capital expenditure amount covered all of the work items that are not covered by the LTSA. During outages, the LTSA does not cover compressor work, cranes, or mobile equipment. The capital expenditures for cranes and mobile equipment comprised the majority of this project amount. Other work completed under this capital expenditure amount include operator and third-party support for valve control replacement. All items captured under this project were required to execute the outage but were outside the LTSA contract scope;

- Jackson 7EA replace compressor stator vanes 1 through 8 ($1 million). This project was emergent work that was discovered during a unit inspection. The work was required to restore the unit to reliable operation in a timely manner;

- Jackson Cooling Tower Fill overhaul ($1.041 million). The original budget for this project was below the $1 million threshold for Part III filing requirement 115, however the discovery of equipment which required repair resulted in higher than expected mechanical and electrical contractor costs;

- Cooke replacement of wicket gates and bushings ($1.523 million). The original budget replacement of the wicket gates was $600,000. However, the discovery of failed head covers which required replacement increased the overall cost of the project. The work was required to maintain safe and reliable operation of the unit;

- Hardy Spill Tube Remediation ($1.595 million). This project continued from 2017 and was projected to be completed in 2019. The original amount projected for 2019 was $1.978 million whereas the combined amount for 2018 and 2019 is projected to be just over $3 million. During the performance of the work, additional items were discovered which required repair including the Expansion Ring, Tail Race Pier Nose, internal nose, and trash rack replacement; and

- Plant Ops Capital replacement ($4.996 million). This project reflects the lease acquisition of the Muskegon waste water land to be utilized for future solar development.

2019 PROJECTED BRIDGE YEAR CAPITAL EXPENDITURES

Q. How does the 2019 projected capital expenditure of $174.044 million compare to the amount of capital reflected in the settlement agreement in Case No. U-20134?

A. The 2019 projected capital expenditure amount of $174.044 million is $5.310 million greater than the Company's projected amount in Case No. U-20134. The Company's as-filed 2019 projected capital expenditure amount of $168.734 million included contingency of $18.376 million as well as $2.719 million of 2019 avoidable capital expenditures for the Karn Units 1 and 2 early retirement scenarios. A compilation of the 2019 projects which have projected capital expenditure amounts greater than $1 million is presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 7.

Q. How does the compilation of capital projects on Exhibit A-12 (SAH-3), Schedule B-5.2, page 7, compare with the 2019 capital projects in Part III filing requirement 115 for Case No. U-20134?

A. A comparison of the projects on Exhibit A-12 (SAH-3), Schedule B-5.2, page 7, with the 2019 projects included in Part III filing requirement 115 for Case No. U-20134 reveals that there are 11 projects on Exhibit A-12 (SAH-3), Schedule B-5.2, page 7, which weren't included in the Part III filing requirement 115 for Case No. U-20134. In addition, there were 20 projects for 2019 that were included in the Part III filing requirement 115 for Case No. U-20134 that are not presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 7.

Q. Please discuss the 2019 capital projects that were included in the Part III filing requirement 115 for Case No. U-20134 that are not presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 7.

A. The disposition of these capital projects is below:

- Campbell Unit 1 upgrade turbine Distributed Control System ("DCS"). This project was originally planned for implementation during a 2019 Campbell Unit 1 outage. However, during the evaluation of the existing Campbell Unit 1 Turbine Control system to identify scope for this upgrade project, a number of operational adjustments and maintenance items were addressed. Upon completion of the operational adjustments and maintenance work, the Campbell Unit 1 Turbine Controls have been operating much more reliably, although they still require significant O&M attention to function properly. The Campbell Unit 1 Upgrade Turbine DCS project was cancelled in 2019 due to the improved operation of the existing system, increased cost estimates for the project, reduced customer benefit, and the risk associated with attempting to retrofit a turbine control system of the Campbell Unit 1 vintage;

- Campbell Unit 2 SAH basket and seal replacement. The implementation of this project was deferred to 2020 and 2021. The projected capital expenditures for this project are $0.500 million in 2020 and $2.425 million in 2021, as discussed later in this direct testimony;

- Campbell Unit 2 catalyst management. The implementation of this project was deferred from 2019 to 2021 to align with Campbell Unit 2 periodic outage schedules. The catalyst material purchase was initiated in 2018, and catalyst modules were received in 2019. The 2018 capital expenditure amount was $0.435 million, the 2019 projected capital expenditure is $0.408 million, and the projected capital expenditure amounts for 2020 and 2021 are $0.700 million and $1.500 million as discussed later in this direct testimony;

- Campbell Unit 2 Turbine Generator High Pressure ("HP")/Intermediate Pressure ("IP") rotor refurbishment. The scope of this project was the refurbishment of the spare HP/IP turbine rotor and control rotor. The project work was reclassified to major maintenance subsequent to the filing of the last rate case;

- Campell Unit 2 replace burner assemblies. The implementation of this project was deferred to 2020 and 2021 as discussed later in this direct testimony. The projected capital amounts for 2020 and 2021 are $0.050 million and $0.550 million, respectively. The condition of the Campbell Unit 2 burner assemblies during the most recent inspection did not warrant immediate replacement. This project was deferred to allow for another inspection and condition assessment of the burners during the 2020 Campbell Unit 2 outage.

Any burners found in poor condition at that time will be planned for replacement in 2021;

- Campbell Unit 2 Pulse Jet Fabric Filter ("PJFF") bag replacement. PJFF bag replacements are planned and budgeted across the fleet based on industry-average PJFF bag replacement intervals. This PJFF bag replacement on Campbell Unit 2 was deferred based on the current condition of the filter bags and the performance of the PJFF as a whole, which indicates the PJFF bags have not yet reached the end of their useful life. This Campbell Unit 2 PJFF bag replacement was deferred to the next outage of opportunity in 2021. The projected capital amounts for 2020 and 2021 are $0.889 million and $2.694 million, respectively;

- Campbell Unit 3 primary air combustion air heater replacement. The projected 2019 capital expenditure for this project is $0.947 million. The Campbell Unit 3 Primary Air Combustion Air Heater Replacement project was implemented in 2019 as planned. Some initial project planning and procurement was completed in 2018, which reduced the total spend in 2019 from the previous rate case Part III filing requirement amount;

- Campbell Unit 3 turbine drain system modification. The Campbell Unit 3 Turbine Drain System Modification project was deferred to 2023/2024. This drain system re-design and replacement is a significant investment, and at the time of deferral in 2018, Campbell Unit 3 had not recently experienced any pipe failures due to the current deficient design. The Company will continue to monitor the condition of the drain system piping and the associated O&M cost of inspections and repairs to determine when project implementation provides economic benefits to customers;

- Campbell site commons design and construct ash cell 5. The Campbell site ash cell construction timeline was developed based on estimated unit run rates and coal ash properties from several years ago. Recently, it was discovered that our landfill volumes are tracking behind the original estimates, based on the rate at which the remaining useable air space within the existing landfill is being filled. This allowed the design and construction of the next Campbell Site Commons ash cell to be deferred by approximately one year to 2020 and 2021 as discussed later in this direct testimony. The projected capital amounts for 2020 and 2021 are $0.577 million and $5.483 million, respectively;

- Karn Unit 2 E1 mill rebuild and upgrade. This 2019 project and its associated capital expenditure was deemed to be avoidable in Case No. U-20134 and, as a result, was not implemented;

- Zeeland new storage building construction. This project was deferred to 2020 and 2021 with a projected capital expenditure amount of $0.5 million in 2020 and $4.5 million in 2021, as I will discuss in more detail later in this direct testimony;

- Jackson X2000 exciter replacement for units 7 through 9. This project was deferred to the April 2021 outage which is required for inspection of the Heat Recovery Steam Generators ("HRSG");

- Jackson LM6000 spare jet engine overhaul. The project work was completed in 2019 as scheduled, however the work was performed under the LTSA with General Electric ("GE"). The Company entered into a new LTSA which included this overhaul work however the new contract was at an increased cost. As a result, the amount of capital budgeted for this overhaul was transferred to the LTSA;

- Hardy Splash Wall Replacement. The majority of the scope has been deferred to 2023 with minor expenditures in 2021 and 2022;

- Webber Downstream Training Wall Repair. Projected capital expenditures for 2019 are almost $200,000, the majority of the scope has been deferred to 2021;

- Webber Unit 1 Overhaul. The projected capital expenditures for 2019 exceed $800,000, with the balance of the work planned to be completed in 2020;

- Webber Left Downstream Spillway Abutment Wall. The projected capital expenditures for 2019 are approximately $100,000, the majority of the scope has been deferred to 2022 and beyond;

- Webber Electrical Safety Project. The entire project was pulled ahead into 2018 and the final cost was $1.631 million, as reflected on Exhibit A-12 (SAH-3), Schedule B-5.2, page 6, line 36;

- Ludington Heating, Ventilation, and Air Conditioning ("HVAC") system upgrade/replacement. The projected capital expenditure amount for 2019 is $0.635 million however the balance of the project has been deferred to the fall of 2020 with project closeout in 2021. As discussed later in this direct testimony, the projected 2020 capital expenditure amount is $4.371 million; and

- Ludington Emergency Diesel Generator ("EDG") and associated switchgear replacement. The projected capital expenditure amount for 2019 is approximately $0.875 million. Due to the fact that the major pond outage was pushed from 2020 to 2021, the balance of this project was deferred to 2021 to align with that outage at a projected capital expenditure amount of $0.637 million.

Q. Please discuss the 2019 capital projects that were not included in the Part III filing requirement 115 for Case No. U-20134 that are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 7.

A. The disposition of these capital projects is below:

- Campbell Unit 3 HP Feedwater Heater 7A replacement ($3.007 million). Due to multiple feedwater heater tube leaks in 2017, the replacement of Campbell Unit 3 HP Feedwater Heater 7A was accelerated. The heater purchase was initiated in 2018, with installation during the 2019 outage at Campbell Unit 3;

- Campbell Unit 3 Control Room HVAC ($2.037 million). This project was added to budget after the rate case filing. This project was initiated after the existing Campbell Unit 3 Control Room HVAC system failed, necessitating replacement. In addition to the replacement of the main HVAC system, the Campbell Unit 3 Emergency HVAC system was also beyond its expected useful life and required replacement;

- Campbell Unit 3 Cross-tie between 8-1 and 8-2 Air Quality Control System ("AQCS") Startup Transformers ("SUTs") ($2.314 million). This project was added to budget after the rate case filing. The scope of the project was to establish a cross-tie between the new 8-2 transformer (AQCS 6.9 kV busses) and existing 8-1 transformers. The cross-tie allows the plant to rely on either of the SUTs during offline periods and during unit start-up. A failure of this feed could result in a plant trip with loss of plant A/C power. The cross-tie allows for a startup bank outage while the unit is online without risk to the unit;

- Campbell Unit 3 FD Fan lube Hydraulic Oil skids replacement ($1.177 million). This project was originally proposed and budgeted as a direct replacement of the existing lube oil and hydraulic oil skids at a projected capital expense of $0.559 million. In order to monitor and control these systems remotely, DCS controls were added to the project scope, which increased the cost and also required the addition of electronic transmitters on associated ancillary equipment;

- Karn Unit 1 SCR second layer catalyst replacement ($1.773 million). This project was originally scheduled for the 2020 outage, however environmental monitoring informed the need to pull this work forward to 2019. The project removed three layers of plugged/deactivated catalyst in the SCR Reactor and installed two new layers of catalyst. Waiting to perform this project in 2020 as planned would have posed a compliance risk, as the existing SCR catalyst layers had very little catalytic activity remaining and were requiring additional ammonia injection to maintain Karn Unit 1 emissions compliance;

- Karn Unit 2 DCS Upgrade (Evergreen) ($1.278 million). At the time of the previous rate case filing, the Karn Unit 2 DCS Upgrade project was planned for initiation in 2018 and installation in 2019. Because the vendor contract was not executed until late 2018, the majority of the project cost is now occurring in 2019, thereby explaining the 2019 actual expenditure versus the $0.960 budgeted amount;

- Jackson Reverse Osmosis ("RO") Water Makeup Expansion ($1.352 million). The original project cost estimate was $0.695 million however it was subsequently discovered that the original project scope did not meet plant specifications to obtain maximum benefit. As a result, the project cost increased in order to purchase the requisite equipment which met plant specifications. Both the mechanical contractor costs and overheads also increased as a result of the compliant equipment;

- Cooke Unit 2 wicket gates ($1.385 million). During unit operation, the closure of the wicket gates failed to stop the unit; the unit spun at synchronous speed with the wicket gates fully closed. As a result, the wicket gate replacement project was added in order to safely and reliably operate the unit;

- Croton Right Abutment Remediation ($4.277 million). This project was added to the 2019 budget after the rate case filing. In 2014, a depression formed behind the right spillway retaining wall. Emergent response was initiated, and the hole was filled with grout and backfilled with material. The hole below the right retaining wall foundation was filled with grout and a grout bag was placed on the spillway apron to help deter additional scour from spilling operations. A feasibility study was performed in 2015 and a condition assessment was performed, resulting in a determination that the retaining wall required replacement. Engineering began in late 2015 and continued through 2017 with the completion of a hydraulics and hydrology ("H&H") study. During project implementation, it was discovered that leakage was excessive, thereby requiring significantly increased dewatering efforts to safely perform the work. In addition, soil retention efforts required significantly more effort than expected as well. The project was required to operate Croton in a safe and compliant manner;

- Croton Rebuild Unit 4 ($1.557 million). The unit was out of service due to failure of the turbine guide bearing as a result of age and condition. The decision to rebuild the unit was made after the rate case filing. The work was required to restore operation of the unit;

- Hardy Auxiliary Spillway ($1.822 million). During 2019, various option studies and risk assessments were performed in order to develop the proper scope of work and provide the proper public safety resolutions. This work was pulled forward due to other dam failures with similar features as Hardy and due to FERC recommendation. Further engineering for this project will be performed in 2020 and 2021 as discussed later in this direct testimony; and

- Rogers Governor replacement ($1.594 million). The original scope for this project included governor replacement for units 2 and 3. Upon inspection, it was determined that the governors for units 1 and 4 required replacement as well. The original project was only budgeted for $0.601 million, the increased scope increased the final projected expenditure amount. The work was required to minimize the impact of oil spills from the original governors.

Q. How did the implementation of these projects impact the 2019 projected capital amount of $174.044 million?

A. The total projected capital expenditure for the 2019 projects included in the Part III filing requirement 115 for Case No. U-20134 was $83.516 million and the total projected capital expenditures for the projects presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 7, is $113.935 million. The $30.419 million increase explains the $26.406 million difference between the capital expenditure amount (less contingency and avoidable) requested in Case No. U-20134 and the projected 2019 capital expenditure amount requested in this proceeding. A portion of the $30.419 million difference includes contingency. An evaluation of the 2019 projects included in the Part III filing requirement 115 for Case No. U-20134 and presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 7, reflects that in total, all contingency amounts for these projects was required for project implementation.

CONTINGENCY

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

A. Yes. Exhibit A-12 (SAH-3), Schedule B-5.2, page 4, columns (d) and (f), identify $7.467 million in total contingencies in 2020 and $10.461 million in total contingencies in 2021.

Q. Why has the Company included contingencies in the requested capital expenditure amount?

A. Budgeting for contingency is an accepted Project Management practice. According to the Association for the Advancement of Cost Engineering International, contingency is "An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs." Contingency is included in some major project estimates and is expected to be used. It is a real item in a project estimate like any other cost, and as such, should be included as a cost. For these reasons contingency costs are appropriate and should be included in the capital expenditures and, ultimately, rate base in this filing. Also, as I previously discussed, an analysis of the 2019 contingency amounts for capital projects greater than $1 million reflects that in total, all contingency was necessary for project implementation.

2020 PROJECTED BRIDGE YEAR CAPITAL EXPENDITURES

Q. Is the projected capital expenditure amount of $119.646 million for the bridge year ending December 31, 2020, on Exhibit A-12 (SAH-3), Schedule B-5.2, page 1, column (d), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (SAH-3), Schedule B-5.2, pages 2 and 3, lines 1 through 112, column (f), $47.187 million of that total capital expenditure amount will be used for projects at Campbell 3, Jackson, and Zeeland, another $22.682 million will allow the Company to complete its $800 million overhaul and other projects at the Ludington Plant, $6.648 million will fund environmental projects at Campbell Units 1 through 3 and

Karn Units 1 and 2, $15.073 million will fund various hydro safety, reliability, and regulatory compliance projects, and $15.161 million will fund projects at Campbell Units 1 and 2 to ensure the safe and reliable operation of those units through their retirement date in 2031. A detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony.

2021 PROJECTED TEST YEAR CAPITAL EXPENDITURES

Q. Is the projected capital expenditure amount of $161.075 million for the test year ending December 31, 2021, on Exhibit A-12 (SAH-3), Schedule B-5.2, page 1, column (f), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (SAH-3), Schedule B-5.2, pages 2 and 3, lines 1 through 16, column (j), $49.012 million of that total capital expenditure amount will be used for projects at Campbell Unit 3, Jackson, and Zeeland; another $21.892 million will allow the Company to complete various regulatory, reliability, and infrastructure projects necessary to support the 50-year license extension at Ludington; $19.058 million will fund environmental projects at Campell Units 1 through 3 and Karn Units 1 and 2; $31.542 million will fund various hydro safety, reliability, and regulatory compliance projects; and $12.869 million will fund projects at Campbell Units 1 and 2 to ensure the safe and reliable operation of those units through their retirement date in 2031. In addition, $12.215 million will fund projects at Karn Units 1 and 2, the majority of which will fund the work required to retire these units in 2023 pursuant to the IRP settlement agreement. A detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony.

Campbell Units 1 and 2

Q. Please explain the Company's projected capital investment for the 12-month bridge year ending December 31, 2020 and 12-month test year ending December 31, 2021 for Campbell Units 1 and 2.

A. The Company plans to invest a total of $17.551 million in 2020 and $24.202 million in 2021 on Campbell Units 1 and 2. The projected 2020 amount includes $15.161 million in non-environmental expenditures and $2.390 million in environmental expenditures and the projected 2021 amount includes $12.869 million in non-environmental expenditures and $11.333 million in environmental expenditures. The non-environmental amounts are shown on both Exhibit A-12 (SAH-3), Schedule B-5.2, page 2, line 1, columns (f) and (j), respectively, and Exhibit A-12 (SAH-3), Schedule B-5.2, page 5, line 1, columns (b) and (d), respectively, and the environmental amounts are shown on Exhibit A-12 (SAH-3), Schedule B-5.2, page 5, line 2, columns (c) and (e), respectively. These capital investments will be facilitated by outages at Campbell Unit 1 in spring 2020 and fall 2021, and outages at Campbell Unit 2 in fall 2020 and spring 2021.

Q. What is the basis for the projected $17.551 million investment in 2020?

A. The projected $17.551 million investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. Those projects which are greater than $1 million are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 8, lines 1 through 3. The basis for the 2020 projects is described below:

- Campbell Unit 1 HP Turbine Blade Replacement ($1,901,000). At the recommendation of the OEM, this project will remove the row 6 blades from the HP turbine rotor, remove the HP turbine rotor for inspection, reinstall the HP turbine rotor, and install new blades from the OEM. During the last major turbine inspection in 2011, the HP turbine row 6 blades were found to have excessive blade foil erosion and foreign object damage. This work will be performed during the spring 2020 turbine inspection outage. Performance of this work will provide for safe and reliable operation of the unit through its retirement date in 2031;

- Campbell Unit 1 Low Pressure ("LP") Turbine blade replacement ($4,274,000). This project will remove and replace the existing four rows of L-0 blades on each of the LP turbine rotors. Campbell Unit 1 was commissioned in 1962 and the existing L-0 blades are original equipment and beyond their useful life. Various repairs were made to the LP turbine rotor L-0 blades during the last major turbine inspection to extend their life until their replacement could be accomplished. This work will be performed during the spring 2020 turbine inspection outage. Performance of this work will provide for safe and reliable operation of the unit through its retirement date in 2031; and

- Campbell Unit 2 DCS and Simulator Upgrade ($1,333,000). This project will upgrade the existing DCS and simulator. The system was last upgraded in 2015 and has an expected life cycle of 5 years. Failure to perform this upgrade could result in security vulnerabilities as well as the inability to maintain software and workstation hardware. The performance of this work will result in continued safe and reliable operation of the unit.

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

- Campbell Unit 2 PJFF Bag Replacement ($889,000). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Campbell Units 1 and 2;

- Campbell Unit 2 Catalyst Management ($700,000). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Campbell Units 1 and 2;

- Campbell Unit 1 Condenser Vacuum Pump replacement ($508,000). This project will replace the existing condenser vacuum pumps. The existing pumps are original plant equipment and are difficult to maintain due to their obsolescence. In addition, the oil injection lubrication system is only marginally effective and requires constant attention from plant operators to maintain requisite condenser vacuum pump performance. The performance of this work will result in increased unit safety and reliability;

- Campbell Unit 2 SAH Basket and Seal Replacement ($500,000). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Campbell Units 1 and 2;

- Twenty-eight additional projects at Campbell Units 1 and 2 totaling $5.265 million support safety and reliability, with each project representing $400,000 or less in expenditures. These projects include replacement of Campbell Unit 2 air and flue gas expansion joints, replacement of the Campbell Unit 2 BFP recirculation flow control and isolation valves, upgrade of the Campbell Unit 1 exciter controls, replacement of the Campbell Unit 1 reheat spray and block valves, and overhaul of the Campbell Unit 1 BFP; and

- There are 14 projects which are common to the Campbell site. Based upon a 43% allocation of the cost to Campbell Units 1 and 2 and a 57% cost allocation to Campbell Unit 3, the various 2020 site commons projects include $2.181 million in projected capital expenditures for Campbell Units 1 and 2. A more detailed discussion of these projects will be provided later in this direct testimony.

Q. What is the basis for the projected $24.202 million investment in 2021?

A. The projected $24.202 million investment will fund numerous safety, regulatory compliance, and reliability projects at Campbell Units 1 and 2. Those projects which are greater than $1 million are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 9, lines 1 through 6. The basis for these projects is described below:

- Campbell Unit 1 alignment of 4160V switchgear with AQCS implementation ($1,000,000). The Campbell Unit 1 switchgear is currently located in the basement. This project will create an intermediate bus that ties in the feed from the new AQCS 7B start up transformer. The new feeds will be designed for higher ratings and the existing gear will be braced for high fault current withstand. The addition of this switchgear allows isolation in the event of a flood, fire, or damage at the 4160V level, versus 138kV presently. Completion of this project will allow operators to pre-emptively take protective action without going completely black light. This project would allow for safer operation and maintenance;

- Campbell Units 1 and 2 SEEG Compliance – Closed Loop w/recirculation ($2,118,293). Company witness Breining discusses the basis for this project which supports the Company's compliance with SEEG in her direct testimony;

- Campbell Unit 2 SAH Basket and Seal Replacement ($2,425,000). This project will remove and replace the SAH hot and cold end baskets and seals and replace the axial seals. The baskets and seals have been in service for an extended period and, based upon condition assessment activities, are in poor condition as evidenced by heavy fouling and erosion, resulting in seal leakage and heat rate degradation. The materials for this project will be procured in

2020 and the basket and seal replacement will be performed during the spring 2021 turbine inspection outage. The performance of this work will result in increased reliability and improved heat rate;

- Campbell Unit 2 Catalyst Management ($1,500,000). This project will remove existing catalyst and install two new layers, consisting of 192 modules, of plate type catalyst in Level 3 and Level 4 of the SCR reactor. In addition, this project will remove 16 existing sonic horns on Level 3 and Level 4 and replace them with new larger sonic horns. Performance of this work will provide continued environmental compliance. The catalyst material purchase was initiated in 2018, the catalyst modules were received in 2019 and project implementation will be accomplished in 2020 and 2021;

- Campbell Unit 2 PJFF Bag Replacement ($2,694,000). This project will replace all 11,760 fabric filter bags and 50% of the bag cages. This equipment was originally installed in 2013 and is part of the AQCS equipment which was installed to comply with EPA requirements. These PJFF bags remove dry fly ash from the gas exiting the boiler and need to be replaced every four or five years to avoid failure due to plugging. Maintaining the integrity of the bags and being able to properly operate the bag cleaning system are necessary for plant operation within regulatory limits. Multiple bag failures could cause the unit to exceed opacity, resulting in unit derate or forced outage based upon the consent decree. The necessary PJFF bags and bag cages will be procured in 2020 and filter bag and cage replacement will be performed during the spring 2021 turbine inspection outage. Performance of this work will provide continued environmental compliance; and

- Campbell Unit 2 LP Turbine Component Replacement ($3,300,000). Per the recommendation of the OEM, this project will replace the first stage blades on both LP rotors, a total of four rows. During the last major inspection, these turbine components were identified as requiring replacement. The performance of this work during the spring 2021 turbine inspection outage will provide continued safe and reliable operation of this unit through its retirement in 2031.

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

- Campbell Units 1 and 2 SEEG – Waste Water Treatment ($882,622). Company witness Breining discusses the basis for this project which supports the Company's compliance with SEEG in her direct testimony;

- Campbell Unit 2 Secondary Air Duct – replace insulation lagging and expansion joints ($795,000). The scope of this project is to remove the existing insulation and lagging, eliminate any duct leaks, repair any damaged duct supports, and install new insulation and lagging. The insulation and lagging on the secondary air duct between the air preheater and the wind box is in a degraded condition and requires replacement. The completion of this project will increase plant efficiency;

- Campbell Unit 1 Mill Overhauls ($696,000). This is a periodic capital project affecting the grinding section and gearbox. Coal Mills experience wear and degradation over time, resulting in degraded performance and increased reliability risk. Degraded performance impacts combustion and efficiency negatively due to increased particle sizes. Capital overhauls are scheduled and performed on a periodic basis;

- Campbell Unit 2 Condenser Circulating Water Pump ("CCWP") Overhaul ($580,000). The CCWPs are in a degraded condition based upon an inspection in May 2018 and pose a reliability risk. This was identified during condition monitoring and preventative maintenance activities. This activity will restore both of the CCWPs to like-new condition and will increase pump reliability and cooling water efficiency.

- Campbell Unit 2 Replacement of Burner Assemblies ($550,000). This item supports the replacement of six of the Campbell 2 boiler burner assemblies. Burner assemblies experience wear over time and these burners have been in service over 19 years. New burners improve combustion, reduce carbon in ash, and improve efficiency. Maintaining the burners in an optimized condition is part of the Mercury and Air Toxic Standards ("MATS") requirements and will support avoidance of forced outages due to burner malfunction and possible windbox fire. The next inspection of the burner assemblies will be performed in 2020 and any burners found to be in poor condition will be replaced in 2021;

- Campbell Units 1 and 2 316b Deep Water Intake ($500,000). Company witness Breining discussed the basis for this project which supports the Company's compliance with the Clean Water Act in her direct testimony;

- Fifteen additional projects at Campbell Units 1 and 2 totaling $3.940 million support reliability and regulatory compliance with each project representing $459,000 or less in expenditures. These projects include Balance of Plant ("BOP") equipment replacements for both units, major motor and pump overhauls for both units, Campbell Unit 2 MBFP overhaul, Campbell Unit 2 Mill Overhauls, Campbell Unit 2 Hydraulic Coupling Rotor Overhaul, Campbell Unit 2 Forced Draft Fan Motor Overhaul, Campbell Unit 2 Combustion Air Heat Exchanger Tube Bank Replacement, Campbell Units 1 and 2 AQCS projects, and Campbell Unit 2 condensate pump overhaul; and

- There are eight projects which are common to the Campbell site. Based upon a 43% allocation of the cost to Campbell Units 1 and 2 and a 57% cost allocation to Campbell Unit 3, the various 2021 site commons projects include $3.221 million in projected capital expenditures for Campbell Units 1 and 2.

A more detailed discussion of these projects will be provided later in this testimony.

Campbell Unit 3

Q. Please explain the Company's projected capital investment for the 12-month bridge year ending December 31, 2020 and 12-month test year ending December 31, 2021 for Campbell Unit 3.

A. The Company plans to invest a total of $9.954 million in 2020 and $19.470 million in 2021 at Campbell Unit 3. The projected 2020 amount includes $8.835 million in non-environmental expenditures and $1.119 million in environmental expenditures and the projected 2021 amount includes $12.445 million in non-environmental expenditures and $7.025 million in environmental expenditures. The non-environmental amounts are shown on both Exhibit A-12 (SAH-3), Schedule B-5.2, page 2, line 8, columns (f) and (j), respectively, and Exhibit A-12 (SAH-3), Schedule B-5.2, page 5, line 3, columns (b) and (d), respectively, and the environmental amounts are shown on Exhibit A-12 (SAH-3), Schedule B-5.2, page 5, line 4, columns (c) and (e), respectively. These capital investments will be facilitated by an outage in the spring of 2021.

Q. What is the basis for the projected $9.954 million capital expenditure for 2020?

A. The projected $9.954 million investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are no projects for Campbell Unit 3 which are greater than $1 million. The following projects are less than $1 million each but are important to regulatory compliance and reliability:

- Campbell Unit 3 Redundant Soot Blowing Air Compressor ("SBAC")($677,000). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Campbell Unit 3;

- Campbell Unit 3 Complete Mill Overhauls ($603,000). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Campbell Unit 3;

- Campbell Unit 3 SBAC Overhaul ($905,107). This project will perform a complete overhaul of the SBAC pursuant to OEM recommendations. This work was last performed in 2015 and the SBAC currently has oil leaks on the high speed pinion and around the horizontal joint of the HP gear box. The purpose of the SBAC is to provide air for removal of ash and slag from the heat absorbing surfaces of the boiler. The SBAC also serves as a primary source to the House Service Air system, Instrument Air System, and Soot Blowers, and it supplies air to the Condensate Polisher System. The SBACs also supply air to Campbell Units 1 and 2. The completion of this overhaul will increase SBAC reliability and reduce the risk of compressor failure. Failure of the unit would likely result in a generating unit derate until the SBAC can be restored;

- Campbell Unit 3 SUT Bushings replacement ($419,585). This project will replace all eight bushings on each of the three 8-1 SUTs. The three SUTs have GE type U and type T bushings which, based on industry experience, are subject to failure. The bushings were manufactured using and insulating dye in the paper of the condenser and the dye is known to degrade over time and result in bushing failure. Implementation of this project will result in continued reliability of the 8-1 SUTs;

- Campbell Unit 3 – Selective Catalytic Reduction Catalyst Management ($326,585). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Campbell Unit 3;

- Thirty additional projects at Campbell Unit 3 totaling $4.131 million support safety, regulatory compliance, and reliability, with each project representing $500,000 or less in capital expenditures. These projects include replacement of HP heater 7A, the addition of a reheater sootblower, replacement of the 480V cables to motor control center 33C2, replacement of the obsolete boiler automated relief valve, relocation of deionization process wells, and replacement of the wood pole for the 8-1 SUT; and

- "Site Common" Projects Shared with Campbell Units 1 and 2 ($2,891,234). Projects that affect the entire site are allocated based on the respective size of the units, with Campbell 3 receiving 57% of the expenditures. These projects are discussed below.

Q. Please explain the Site Commons projects.

A. There are 14 Site Commons projects in 2020 with a total dollar amount of $5.072 million subject to allocation as described above. One of these projects is greater than $1 million and it is presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 8, line 4. The basis for this project is described below:

- Campbell Bottom Ash Tanks Chemical Treatment System ($1,192,850). This environmental compliance project will install a chemical treatment system to dose coagulant and flocculent chemicals into the bottom ash tank system to help promote dropout of suspended solids prior to the transport water being discharged into the site ditching system. The installation of the chemical treatment system will provide for the continued ability to maintain compliance with National Pollutant Discharge Elimination System permit requirements for outfall 002A. The permit requirements include compliance with monthly total suspended solids ("TSS") limit of 30 mg/L, compliance with daily TSS limit of 50 mg/L, compliance with visual narrative standard requirements: the receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.

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

- Dry Ash Cell 6 Landfill Construction ($577,140). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Campbell site commons;

- Replace Fuel Handling Conveyor Belts ($453,400). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Campbell site commons;

- Campbell Phase 2 Potable Water Lead and Copper Project ($449,950). This project will design and install a chemical treatment system for the site potable water system to manage system corrosivity. The site received an Action Level Exceedance for Lead notification from the MDEQ, in October of 2016. In cooperation with the Ottawa County Health Department and the MDEQ, the site has been working through corrective actions in an attempt to resolve the issue. These efforts have thus far been unsuccessful in eliminating the root cause of the exceedances, and the potable water system continues to be in non-compliance due to elevated lead and copper. Based upon sampling, the non-compliance is caused by having a water source that is mildly corrosive in nature, thereby stripping lead and copper components into the drinking water. The site has until September 2020 (48 months from Exceedance Notification date) to demonstrate potable water system compliance; and

- Ten additional site common projects at the Campbell site totaling $2.399 million support safety and reliability, with each project representing $420,000 or less in expenditures. These projects include replacement of small pumps and motors, replacement of small valves and instrumentation, replacement of the RO membrane, and Urea Based Ammonia Supply ("UBAS") upgrades.

Q. What is the basis for the projected $19.470 million investment in 2021?

A. The projected capital expenditure amount of $19.470 million will fund numerous safety, regulatory compliance, and reliability projects at Campbell Unit 3. There are eight projects for Campbell Unit 3 which are greater than $1 million, and which are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 9, lines 7 through 14. The basis for these projects is described below:

- Campbell Unit 3 SEEG - Waste Water Treatment ($1,206,000). Company witness Breining discusses the basis for this project which supports the Company's compliance with SEEG in her direct testimony;

- Campbell Unit 3 SEEG – Closed Loop with recirculation ($2,893,000). Company witness Breining discusses the basis for this project which supports the Company's compliance with SEEG in her direct testimony;

- Campbell Unit 3 – SCR Catalyst Management ($1,959,510). The scope of this project is the ongoing management of the SCR catalyst. The scope of this project for 2020 is the completion of SCR performance testing and closeout of the 2019 catalyst layer replacement project. The 2021 project scope is the procurement of catalyst modules for installation in the spring 2022 outage. Catalyst layers were replaced during the fall 2019 outage and the performance testing to be performed in 2020 requires mild weather for completion. The performance of this work will maintain the functionality of an environmental related system by removing old, exhausted layers of catalyst and replacing with new layers of plate type catalyst, thereby improving the efficiency of the SCR;

- Campbell Unit 3 CO-O2 monitor replacement ($1,044,600). The ability to monitor post-combustion carbon monoxide does not currently exist on Campbell Unit 3; existing monitors only measure oxygen. The inability to adequately measure the flue gas results in poor combustion and increased difficulty in efficiently controlling NO_x. The replacement monitors will be installed during the spring 2021 outage and will result in increased efficiency and improved environmental monitoring and control;

- Campbell Unit 3 Reheater Sootblower ($1,250,000). The scope of this project is to add sootblowers for the reheater. Ash buildup on the top/front of the reheater directly behind the partition wall causes gas/ash laning which leads to localized overheat and erosion conditions. This condition has caused forced outages in the past. Due to the configuration of the tubing, the amount of collateral damage is typically high when a failure occurs in this area. Additionally, the size of the unit makes detection difficult at the early stages of a leak, leading to significant secondary damage prior to leak identification. The additional sootblowers would be mounted in an existing set of manways on the 12th floor of the boiler. These would blow the top/front of the reheater, keeping ash from building to a level that would cause laning and erosion. The sootblowers would need to be configured such that they could be easily disconnected and pulled back, so the opening could still be used as an entry way into the boiler. The sootblowers would need to be capable of indexing so they do not blow on the adjacent partition wall tubing.

- Campbell Unit 3 Redundant SBAC ($1,200,000). High furnace exit gas temperatures ("FEGT") and economizer exit gas temperatures lead to unit derates due to high SCR unit inlet temperatures. High FEGT also leads to ash plugging in the economizer; leading to forced outages and extensive repairs. The high FEGT are a direct result of soot building on the tube surface, insulating the heat transfer of the furnace and carrying the heat to the SCR. This project will split the north and south risers, making each side an independent system allowing for increased sootblowing capability to reduce the soot build up. This project will evaluate, design, and implement air supply system upgrades to improve unit efficiency and availability. This is a 2-year project with the engineering and material procurement accomplished in 2020 at a projected capital expenditure amount of $250,000 and the project implementation in the spring 2021 outage;

- Campbell Unit 3 Replace Lake Michigan Intake Screens ($1,270,000). The Campbell Lake Michigan cooling water intake waster system is composed of 28 cylindrical screens. These screens have been in service for approximately 40 years and are deteriorating to the point of screen failure. This project will replace all of the intake screens over the course of four years with one array replaced per year beginning in 2019. Implementation of this project will result is safe, dependable, and uninterrupted cooling water to Campbell Unit 3 until its planned retirement in 2040; and

- Campbell Unit 3 Complete Mill Overhauls ($1,235,000). This project will begin the periodic rebuild of the Unit 3 Coal Mills in 2020 and continue in 2021. Coal Mills experience wear and degradation over time, resulting in reduced performance and increased reliability risk. Suboptimal performance negatively impacts combustion and efficiency due to increased particle sizes. This project will begin the periodic rebuild of the Coal Mills for Campbell Unit 3. The Company has spent an average of $718,000 for the periodic rebuild of Campbell Units 1 and 2 mills over the last five years. The performance of this work will maintain the high level of unit availability necessary to provide customer value.

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

- Campbell Unit 3 AQCS projects ($750,000). These projects will support the maintenance and periodic replacement of AQCS equipment to maintain system reliability and ensure environmental compliance. Campbell Unit 3 has extensive AQCS equipment (Flue Gas Demineralizer, SCR, and PJFF) which require periodic equipment replacements and improvements to maintain environmental compliance. This same level of investment is projected per year from 2021 through 2024;

- Campbell Unit 3 Purchase and Install a third Auxiliary Boiler ($686,800). The scope of this project is to purchase and install a third auxiliary boiler at Campbell Unit 3. The existing auxiliary boilers do not provide enough auxiliary steam to provide adequate plant heating in the winter if Campbell Units 1, 2, and 3 are out of service; thereby resulting in a risk of freezing piping in the main unit and other systems. The project will include an assessment of the auxiliary steam demand to support the new boiler specifications. Existing plant systems including deaerator, blowdown, and feedwater systems, are already in place to support the installation;

- Campbell Unit 3 Fuel Handling/Infrastructure Replacements ($500,000). Due to normal wear, fuel handling equipment requires periodic replacement. Specific conveyor belts and rail road sections are defined for replacement in the next 1-2 years, and additional equipment will be identified for replacement for 2021 and beyond based on condition. A total capital expenditure of almost $5.2 million is projected through 2024 to replace conveyor belts, chutes, and other major fuel handling equipment and infrastructure based on condition. This project work will result in continued fuel handling reliability;

- Campbell Unit 3 Boiler Leak Detection System ($492,200). Early-stage reheater leaks at Campbell Unit 3 are difficult to detect due to the size of the unit. Current methodologies for identification of reheater leaks includes trending water makeup rates and audible detection. This project will install an acoustic monitoring system at various locations on the outside of the boiler, adjacent to the reheater. In addition, area monitors will be installed in the penthouse. This project will result in the ability to identify early-stage leaks and implement corrective action in a timelier manner, resulting in improved plant efficiency and reliability;

- An additional five smaller projects at Campbell Unit 3 totaling $512,310. These projects, which each involve less than $200,000 in capital expenditures in 2021, are intended to further maintain reliability and operations of Campbell Unit 3, and includes BOP equipment replacements, replacement of the EHC fluid purification system which is at end of life, replacement of the controls for the diesel generator which are at end of life, installation of online dissolved gas analyzers for the Campbell Unit 3 Generator Step-Up Transformers ("GSUs") to improve fault detection, replacement of the obsolete hydrogen gas dryer on the Campbell Unit 3 generator, and installation of a boiler slag-reducing coating; and

- Site Common Projects, including environmental projects, shared with Campbell Units 1 and 2 ($4,270,343). Projects that affect the entire site are allocated based on the respective size of the units, with Campbell Unit 3 receiving 57% of the expenditures.

Q. Please explain the Campbell Site Commons projects.

A. There are eight Site Commons projects in 2021 with total dollar amount subject to allocation as described above. One of these projects is greater than $1 million and it is presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 9, line 15. The basis for this project is described below:

- Dry Ash Cell 6 Landfill Construction ($5,482,830). The on-site landfill is the only licensed and approved method for disposal of fly ash at the Campbell facility. The landfill is projected to run out of usable airspace in 2022 unless additional airspace is constructed. The landfill consists of seven adjacent cells that, when completed and filled, will be integrated together, sealed, and covered. This project is for the design and construction of Ash Cell 6 to be used for the continued disposal of fly ash. The project design will be accomplished in 2020 and the construction will be completed in 2021.

The following project is less than $1 million but is important to reliability:

- Replace Fuel Handling Conveyor Belts ($427,000). The conveyor belts that provide coal to the plant have a finite useful life and must be monitored on a regular basis and replaced when necessary. The projected expenditure will be used to procure the necessary conveyor belt materials for installation when condition assessments identify the need. The projected investment will also fund the installation and hot vulcanization of the belting. A similar funding amount is included in both the 2020 and 2021 projected capital expenditures; and

- Six additional site commons projects at the Campbell site totaling $1.582 million support safety, regulatory compliance, and reliability, with each project representing $426,000 or less in expenditures. These projects include completion of the bottom ash tanks chemical treatment system installation, replacement of the fuel handling dust collector bags, replacement of small pumps and motors, replacement of small valves and instrumentation, and UBAS upgrades.

Karn Units 1 and 2

Q. Please explain the Company's projected capital investment for the 12-month bridge year ending December 31, 2020 and the 12-month test year ending December 31, 2021 for Karn Units 1 and 2.

A. The Company plans to invest a total of $5.852 million in 2020 and $12.915 million in 2021 on Karn Units 1 and 2. The projected 2020 amount includes $2.712 million in non-environmental expenditures and $3.140 million in environmental expenditures and the projected 2021 amount includes $12.215 million in non-environmental expenditures and $0.700 million in environmental expenditures. The non-environmental amounts are shown on both Exhibit A-12 (SAH-3), Schedule B-5.2, page 2, line 15, columns (f) and (j), respectively, and Exhibit A-12 (SAH-3), Schedule B-5.2, page 5, line 5, columns (b) and (d), respectively, and the environmental amounts are shown on Exhibit A-12 (SAH-3), Schedule B-5.2, page 5, line 6, columns (c) and (e), respectively. These capital investments will be facilitated by outages at Karn Unit 1 in spring 2020 and fall 2021, and outages at Karn Unit 2 in fall 2020 and 2021.

Q. What is the basis for the projected $5.852 million capital investment for Karn Units 1 and 2 in 2020?

A. The projected $5.852 million capital investment for 2020 will fund safety and regulatory compliance/environmental projects. There are two projects which are greater than $1 million, and they are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 8, lines 5 and 6. The basis for these projects is described below:

- Karn Unit 1 and 2 Landfill Remedial Action Plan ($1,200,000). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Karn Units 1 and 2; and

- Karn Unit 2 SCR Catalyst Replacement ($1,000,000). The scope of this project is the replacement of two layers of existing catalyst. The SCR is required for compliance with nitrogen dioxide emission rate limits. As the catalyst ages, it deactivates due to poisons and ash fouling and needs to be replaced periodically. Performance of this project will maintain environmental compliance of the unit through its retirement in 2023.

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

- Karn Units 3 and 4 decoupling and Karn Units 1 and 2 Decommissioning ($889,766). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Karn Units 1 and 2;

- Karn Unit 2 PJFF bag replacement ($695,000). The scope of this project is the procurement and installation of the PJFF bags. There are 10,160 bags total in 10 chambers and the bags are tested on an annual basis for integrity. The bag replacement will be performed during the fall 2020 outage. Project completion will ensure the unit is able to maintain environmental compliance through its retirement in May 2023;

- Karn Fuel Handling Conveyor Belt Replacement ($340,000). The scope of this project is to replace the Karn Units 1 and 2 fuel handling 'A' conveyor belt and pulleys along with the vertical and horizontal supports for the bend and take-up pulleys. The existing pulleys are worn and the supports are damaged, requiring temporary repairs until equipment replacement can be accomplished. Replacement of the equipment is necessary to ensure continued reliable operation of Karn Units 1 and 2;

- Eight additional projects at Karn Units 1 and 2 totaling $1.262 million support safety and reliability, with each project representing $275,000 or less in expenditures. These projects include replacement of the element on the Karn Unit 1 BFP 1B, replacement of the element and remachining of the barrel for the Karn Unit 2 BFP 2A, and installation of NO_x analyzers on Karn Unit 2; and

- There are six projects which are common to the Karn site. Based upon a 50% allocation of the cost to Karn Units 1 and 2 and a 50% cost allocation to Karn Units 3 and 4, the various 2020 site commons projects include $0.466 million in projected capital expenditures for Karn Units 1 and 2. A more detailed discussion of these projects will be provided later in this direct testimony.

Q. What is the basis for the projected $12.915 million capital investment in 2021?

A. The projected $12.915 million capital investment will fund safety and regulatory compliance projects at Karn Units 1 and 2. There is one project which is greater than $1 million, and it is presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 9, line 16. The basis for this project is described below:

- Karn Units 1 and 2 decommissioning ($10,295,862). The scope of this project is the separation of various utilities/systems in order to isolate Karn Units 3 and 4 from Karn Units 1 and 2 prior to their retirement in May 2023. Capital expenditure amounts totaling almost $29 million are projected from 2020 through 2023 to accomplish this work scope. Projected capital expenditure amounts of $0.890 million for 2020 and $10.296 for 2021 are included in the Company's request for relief in this proceeding. These capital expenditures are necessary to comply with the Company's MPSC-approved IRP. The major scope items included in the almost $29 million capital expenditure amounts are as follows:

    - Utility Separation - Compressed Air, City Water, Sanitary, Natural Gas, etc.;
    - Demineralized Water System Installation;
    - LP House Service Water Modifications;
    - Intake and Discharge Channel Freeze Protection;
    - 138kV Substation Controls;
    - Power for Auxiliary Buildings;
    - Reconfigure Communication Network;
    - Relocate House Service Water Chlorination System;
    - Distributed Control System Modifications; and
    - Electrical Distribution for New Loads.

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

- Karn Landfill Remedial Action Plan ($500,000). The purpose of this project is to maintain long term compliance with site-specific water quality monitoring. The Karn Landfill is governed under Solid Waste Operating License No. 9440, which requires compliance with a Hydrogeological Monitoring Plan that is limited to an Interim Remedial Action System in the form of a groundwater extraction and treatment system located along the solid waste boundary of the landfill located adjacent to Saginaw Bay and a groundwater mixing zone. The groundwater treatment system was put into service in 2017 and currently comprises an element of the groundwater compliance solution for the landfill. Leading indicators from groundwater monitoring wells located on the perimeter embankment dike evaluated against episodic excursions of elevated arsenic concentrations indicate that a more robust closure strategy will be needed to meet final closure certification. The final closure certification from EGLE will necessitate finalization of interim systems (groundwater mixing zone and groundwater extraction system) to be evaluated against other alternatives before final closure can be accepted. Various long-term compliance options were evaluated, and the selected alternative was to maintain and optimize groundwater extraction system, complete a biomass redox study to evaluate attenuation mechanism and likelihood of success, and to evaluate other constructed systems to replace or work in coordination of the groundwater extraction and treatment system. During 2020 the scope of this project is the completion of detailed engineering and the start of groundwater treatment system installation. Installation of the groundwater treatment system will be completed in 2021 along with performance testing and project closeout;

- Karn Units 1 and 2 Major Motor and Pump Overhauls ($250,000 each). This project will overhaul major motors and/or pumps based on established rebuild schedules and equipment condition assessments. Large pumps and motors require overhauls/rewinds on a regular schedule and the work will provide continued equipment reliability to provide safe operation through the May 2023 retirement date;

- Eight additional small projects at Karn Units 1 and 2 totaling $1.309 million to support reliability and regulatory compliance, with each project representing $250,000 or less in expenditures. These projects include fuel handling rail road replacement, Karn Unit 2 SCR Catalyst replacement, Karn Unit 2 PJFF bag replacement, Karn Units 1 and 2 BOP Equipment Replacements, and Karn Units 1 and 2 Fuel Handling/Infrastructure Replacements; and

- There are five projects which are common to the Karn site. Based upon a 50% allocation of the cost to Karn Units 1 and 2 and a 50% cost allocation to Karn Units 3 and 4, the various 2021 site commons projects include $0.310 million in projected capital expenditures for Karn Units 1 and 2. A more detailed discussion of these projects will be provided later in this direct testimony.

Karn Units 3 and 4

Q. Please explain the Company's projected capital investment for the 12-month bridge year ending December 31, 2020 and the 12-month test year ending December 31, 2021, for Karn Units 3 and 4.

A. The Company plans to invest a total of $6.886 million in 2020 and $11.103 million in 2021, as shown on Exhibit A-12 (SAH-3), Schedule B-5.2, page 2, line 22, columns (f) and (j), respectively. These capital investments will be facilitated by outages at Karn Units 3 and 4 in spring 2020 and fall 2021.

Q. What is the basis for the projected $6.886 million capital investment in 2020?

A. The projected $6.886 million capital investment in 2020 will fund numerous reliability projects at Karn Units 3 and Unit 4 in 2020. There are two projects which are greater than $1 million, and they are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 8, lines 7 and 8. The basis for these projects are described below:

- Karn Unit 4 EHC Repair and Retrofit ($2,300,000). The EHC condition has degraded such that accurate control of the main steam control valves and re-heat steam control valves is very difficult, resulting in unstable operations at startup and variations in MW output when online. This project will provide more accurate control of the turbine valves. The purpose of this project is to address various issues with the current EHC system. The existing Siemens - Allis Chalmers HMN-60HZ-SC Steam Turbine uses a LP EHC system to actuate the turbine steam valves. The current EHC system has one servo to control all 16 actuators. The EHC system controls 16 valves for the Karn Unit 4 turbines; (4) HP control, (4) HP stop, (4) intermediate pressure control, and (4) intermediate pressure stop valves. These valves provide necessary fluid flow and pressure to position the turbine actuators for speed/load (MW)/Pressure Control. The actuators in this system do not maintain the desired valve position. This failure results in 30 rpm swings during startups which delays the system from getting online. Once online, Karn Unit 4 will experience 10-20 MW swings due to lags between system demand and valve actuator responses. There are EHC pressure oscillations that cause the turbine valve position oscillations. This project will also include the development of a DCS Empirical (Medium-Fidelity) Simulator for operator training purposes. The implementation of this project will improve unit reliability by more accurately controlling speed (within 10 rpm of setpoint) on startup, controlling unit load to within 3 MV after breaker closure, enhance the speed control from turning gear to synchronous operation, increase/decrease electrical load at a controlled rate after the generator breaker is closed, provide ability to prevent overspeed after trip initiation due to valve closing sequence, reduce the number of required start-ups for operator training purposes, and allow for the testing of logic and graphic changes for future logic enhancements and projects; and

- Karn Unit 4 Cooling Tower Internal Structure Replacement ($2,000,000). The scope of this project is the multi-year replacement of the structural timbers, remaining stacks and fan blades. The wooden structure is original equipment and has decayed since its installation. The cooling tower provides cooling water for the condenser. The wooden cooling tower structure supports 18 large fans that pull air through the water to drive the evaporation process to cool the water. The wooden structure also supports large water pipes that carry the cooling water to the fill. The water flow to the tower is approximately 240,000 gallons per minute. All of this weight is supported by the wooden structure as it is conveyed to the tower and cascades over the fill. Implementation of this project will provide for reliable operation of the unit through its retirement in 2031.

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

- Karn Units 3 and 4 Startup Optimization ($400,000). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Karn Units 3 and 4;

- Karn Unit 4 static exciter overhaul ($400,000). The scope of this project is the replacement of the controls portion of the Karn Unit 4 static exciter with a GE EX2100e Redundant Digital Front End, similar to the controls already in place on the Karn Unit 3 exciter. The new digital front end will be installed on the existing Karn Unit 4 Exciter and will be controlled through the existing DCS communications link. Based on recent inspections, the Karn Unit 4 Static Exciter condition warrants a rebuild to maintain unit reliability, thereby supporting continued operation through the unit's retirement date in May 2031;

- Karn Unit 4 Turbine Supervisory Instrumentation ("TSI") Vibration System ($315,000). The scope of this project is the replacement of the existing turbine vibration system. The existing TSI turbine vibration system is approximately 15 years old, is obsolete, past end of life, and has limited OEM support. The current PC for interface and configuration into the system is running Windows 7 and will not be able to be patched after January 2020. The system integration with the Ovation DCS is through a data communication link with the existing vibration monitoring system and is used for data display. Configuration and troubleshooting performed using the PC for the existing vibration monitoring system is very cumbersome, and the existing system does not provide for the vibration diagnostics capabilities available with a modern system. The implementation of this project will enhance the Karn Unit 4 protection system with supported hardware and software and will provide for increased trouble-shooting and analytical capability (waterfall and waveform plots on the Ovation system) for turbine vibration issues along with tight integration with the unit control system (DCS). The project will also provide for regularly updated software with DCS Evergreen projects and will reduce the use of third-party stand-alone systems that require additional PC patching and cyber security monitoring. This project is being performed in conjunction with the Karn Unit 4 EHC project and will take advantage of the scaffolding which will be in place for that project to run new wiring from the existing field boxes to a new central cabinet at the turbine office;

- Six additional small projects at Karn Units 3 and 4 totaling $1.005 million to support reliability and regulatory compliance, with each project representing $260,000 or less in expenditures. These projects include fuel handling rail road replacement, Karn Units 3 and 4 Induced Draft and Forced Draft Fan vibration systems, replacement of the Karn Unit 4 station power cables and replacement of the Karn Units 3 and 4 sync wire; and

- There are 6 projects which are common to the Karn site. Based upon a 50% allocation of the cost to Karn Units 1 and 2, and a 50% cost allocation to Karn Units 3 and 4, the various 2020 site commons projects include $0.466 million in projected capital expenditures for Karn Units 3 and 4. These projects include Karn small tools and equipment ($210,000), Karn small pumps and motors ($100,000), Karn small valves and instrumentation ($210,000), and Karn (Generation) Emerson Power and Water Cyber Security Suite Upgrade.

Q. What is the basis for the projected $11.103 million capital investment in 2021?

A. The projected $11.103 million capital investment in 2021will fund safety and reliability projects at Karn Units 3 and 4. There are three projects which are greater than $1 million, and they are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 9, line 17-19. The basis for these projects is described below:

- Karn Units 3 and 4 Parking Lot Replacement ($1,000,000). The scope of this project is the replacement of the parking lot using the Full Depth Reclamation process. Project scope includes the installation of a new catch basin and tie into the existing site storm drainage. The existing parking lot is in poor condition with numerous cracks and drainage issues;

- Karn Unit 3 Cooling Tower Rebuild ($2,500,000). The scope of this project is the replacement of the structural timbers, remaining stacks, and fan blades. The wooden structure is original equipment and has decayed since its installation. The cooling tower provides cooling water for the condenser. The wooden cooling tower structure supports 18 large fans that pull air through the water to drive the evaporation process to cool the water. The wooden structure also supports large water pipes that carry the cooling water to the fill. The water flow to the tower is approximately 240,000 gallons per minute. All of this weight is supported by the wooden structure as it is conveyed to the tower and cascades over the fill. Implementation of this project will provide for reliable operation of Karn Unit 3 through its retirement in 2031; and

- Karn Units 3 and 4 Startup Optimization ($3,900,000). The scope of this project is to improve reliability and efficiency of Karn Units 3 and 4. The scope of this project for 2020 is the retubing of the Karn Unit 3 and 4 auxiliary boilers as required to restore reliability. In addition, this 2020 project scope will investigate the installation of a startup BFP on Karn Unit 3 to allow unit startup with a single auxiliary boiler. The tubing for the auxiliary boilers is past its end of life due to events which have left residual stress in the tubing; resulting in multiple tube failures on each boiler every year. These failures put the operation of Karn Units 3 and 4 at risk thereby increasing equipment forced outage rate and each unit's capacity value. The scope of this project for 2021 includes the procurement and installation of a startup BFP.

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

- Karn Unit 4 CCWP overhauls ($400,000). The scope of this project is to rebuild the four CCWPs. Karn Unit 3 has experienced unit derates as high as 85 MW as a result of condenser back pressure. As a result of the derates, the equipment performance testing group calculated and measured the CCWP flow at 205,000 GPM. The design flow for the CCWPs is 281,000 GPM. The CCWP overhauls will restore the pump capacity and allow the unit to avoid derates and, as a result, provide for reliable Karn Unit 4 operation through its retirement in 2031;

- Karn Unit 4 Cooling Tower Bypass Line Repair ($600,000). The scope of this project is to replace the Karn Unit 4 bypass lines. The existing cooling tower bypass lines are original plant equipment, were temporarily repaired in 2016 and, based upon condition assessments, are at their end of life. The Karn Unit 4 cooling tower basin trending shows an approximate loss of 50,000 gallons/day of water when not circulating. An economic based reliability inspection has proven that the leak is in the (2) tower bypass lines that come into the bottom of the basin. This does not affect the operation or availability of the unit. However, when a zebra mussel treatment is applied to house service water ("HSW"), the treated water is contained within the Karn Units 3 and 4 cooling tower basin and only released after approval from the EGLE;

- Karn Units 3 and 4 Screen Drive Replacement ($950,000). The scope of this project is to replace the screen drives for the HSW. The HSW screen drives for Karn Units 3 and 4 have failed and, as a result, the screens no longer have the ability to travel. Because the screens don't have the ability to travel, online cleaning is not an option. The restoration of the traveling screen functionality will improve the reliability of the HSW system;

- Karn Unit 3 Combustion Air Heater 3BA Replacement ($566,000). The scope of this project is to replace one air heater panel section. The combustion air heater has a total of 348 finned tubes that preheat the combustion air. The loss of surface area due to plugged tubes results in lost boiler efficiency, opacity concerns, and potential damage to reheat and primary superheat tubing. The performance of this work will improve plant reliability and efficiency;

- There are four additional projects at Karn Units 3 and 4 totaling $0.877 million to support reliability with each project representing $300,000 or less in expenditures. These projects include DCS automation projects for Karn Units 3 and 4, replacement of the Karn Unit 4 air heater replacement and conversion of the Karn Units 3 and 4 Tank Farm programmable logic controller ("PLC")-DCS; and

- There are five projects which are common to the Karn site. Based upon a 50% allocation of the cost to Karn Units 1 and 2 and a 50% cost allocation to Karn Units 3 and 4, the various 2021 site commons projects include $0.310 million in projected capital expenditures for Karn Units 1 and 2. These projects include Cyber security, small tools and equipment, small pumps and motors, and small valves and instrumentation.

Zeeland

Q. Please explain the Company's projected investment for 12-month bridge year ending December 31, 2020 and 12-month test year ending December 31, 2021 for Zeeland.

A. The Company plans to invest $13.708 million in 2020 and $20.222 million in 2021 at Zeeland, as shown on Exhibit A-12 (SAH-3), Schedule B-5.2, page 2, line 29, columns (f) and (j), respectively. These capital expenditures will be facilitated, in part, by an outage in spring 2020 and fall 2021. The Company has a LTSA with GE that covers many reliability issues at Zeeland.

Q. What is the basis for the projected $13.708 million capital investment in 2020?

A. The projected $13.708 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at Zeeland. There is one project which is greater than $1 million, and this project is presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 8, line 9. The basis for this project is described below:

- Zeeland LTSA ($7,557,000). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Zeeland.

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

- Construction of New Storage Building to Support Major Overhaul Work ($500,000). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Zeeland;

- Zeeland Cooling Tower Fill ($855,000). This project will replace the existing cooling tower fill material and drift eliminator material with new low fouling film fill and drift eliminator as part of the normal fill requirement process. The purpose of the cooling tower system is to remove excess heat from the steam cycle, and the existing cooling tower is marginally sized to meet the heat rejection needs of the plant, sometimes resulting in plant derates. An evaluation of the cooling tower in May 2019 found the fill material to be brittle and in poor condition. Most of the existing fill material is original and well beyond its end of life. The installation of the new fill material will eliminate the existing performance limitations and improve heat rate, resulting in an economic benefit to customers;

- Zeeland Duct Burners 2A and 2B Burner Management System ("BMS") Controls Replacement ($600,000). The scope of this project is the replacement of the existing Duct Burners 2A and 2B BMS Controls PLC with the latest PLC version. In addition, this project will replace the main gas shut-off valves and the BMS pressure switches. The existing Zeeland duct burners 2A & 2B have an obsolete BMS control system. The control equipment is no longer available from the OEM and spare parts availability is limited. The implementation of this project will restore maintainability of the BMS PLC, assure main gas double block shutoff through replacement of the main gas shut-off valves, and restore BMS protection by replacing the existing gas pressure switches with new switches;

- Zeeland Generating Station Revenue Grade Metering on 2A, 2B, and 2C ($430,000). The scope of this project is the installation of revenue grade metering on combined cycle generating units 2A, 2B, and 2C. The revenue grade metering system is a requirement of the Company's proposed contract with HSC for accurate monitoring of our generation output; and

- Thirty additional projects at Zeeland totaling $3.766 million supporting safety, reliability, regulatory compliance, infrastructure, and operations, with each project representing less than $370,000 or less in expenditures. These projects include base outage capital, replacement of the Zeeland GSU annunciators, turbine control system upgrade, BFP overhaul, BOP DCS upgrade, and small pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected $20.222 million capital investment in 2021?

A. The projected $20.222 million capital investment in 2021 will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at Zeeland. There are two projects which are greater than $1 million, and they are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 9, lines 20 and 21. The basis for these projects are described below:

- Zeeland LTSA ($8,900,000). 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 we execute the normal planned maintenance and inspections according to the recommended schedules, we will mitigate unexpected pre-mature failures of the equipment. This will help us minimize ROR and it will optimize our customer value for the site. Normal maintenance will ensure we have continued reliable operation of the units; and

- Construction of New Storage Building to Support Major Overhaul Work ($4,500,000). The scope of this project is the design and construction of a new storage building on the Zeeland site. During 2020, the planning, engineering, design, and preparation work will occur with construction scheduled for 2021. The current covered storage is not adequate for storage of components during major overhauls. This new building will allow for deliveries and storage of materials for the site in a centralized, organized location. The site also lacks office space to house project and engineering resources, this building will provide adequate space to house the required employees to run the site and projects. An additional driver of the new building is safety, as the site does not have a rated storm shelter space to protect employees during an emergent situation. The new building will have an environmental safety shelter included.

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

- Zeeland Load Commutating Inverter ("LCI") Upgrade for Phase I (simple cycle) Generation ($750,000). This project will upgrade the LCIs for the turbine generator starting system. The existing LCI control system is obsolete and at the end of its expected life; the installed circuit boards are more than 18 years old and available spare parts are scarce. The LCIs perform a critical function in combustion turbine startups and have sophisticated computer hardware and software that interface with the Excitation System and Turbine Control systems during operation. This upgrade will ensure continued reliability of the LCI and turbine-generator starting system and provide the LCI system with the latest hardware and software to ensure seamless interface with the recently upgraded turbine control system and planned upgrades to excitation;

- Install New 4160V Cross tie ($800,000). This project will install a 4160V cross tie between the Phase I and Phase II (combined cycle) generators to provide a reciprocal backup power source for each Phase's external power source. Currently, the only external power source is fed through the GSU and station power transformers. If the GSU, Generator Breaker, Substation Equipment, or 4160V Main Breaker is out of service for maintenance or as a result of failure, only minimal A/C Power would be available to the site through two 480V feeds. This project will allow all critical plant equipment to be operated in the event of a loss of the external power source, thereby avoiding the potential for equipment failure due to the loss of power to various site buildings, turbine turning gears, and critical pumps which provide cooling for major plant equipment. In addition, this would significantly reduce the challenges encountered in performing outage-related activities, resulting in reduced O&M expense as well as outage duration;

- LTSA Extra work ($700,000). This project will address the critical items needed in order to execute the major outage activities that are not included in the normal planned maintenance scope of the LTSA. These additional items needed to execute the major outage work are: cranes, mobile equipment, and special lifting equipment required to disassemble and reassemble the units;

- Zeeland RO System Controls and Variable Frequency Drive ("VFD") Replacement ($600,000). This project will migrate the RO system controls into the BOP DCS. The existing RO control system is obsolete, the control system support from the OEM expired in 2017 and replacement parts are no longer available. In addition, the VFDs which operate the RO system water pumps are obsolete as well and replacement parts have been unavailable for more than 10 years. Finally, the software on the human machine interface ("HMI") computers is not up to date due to a lack of a LTSA and, with support for the current version of Windows O/S expiring in early 2020, an upgrade of the HMI software is necessary. This project will result in improved equipment reliability, consolidation of the cyber security process with the integration of the RO control system into the DCS, and provision of a platform for future chemistry data management in the DCS once the chemistry lab upgrades are complete in 2021;

- Replace unit 1A and 1B EX-2000 exciters to EX-2100 ($573,000). The scope of this project is to procure and replace EX2100e to match recently installed phase 2 equipment. The specific scope is to replace existing control boards and components with limited expected service life (capacitors, fans) as well as tune and test the upgraded system to meet Consumers Energy operational and North American Electric Reliability Corporation ("NERC") requirements. The exciters (GE EX2000) are critical components for the generator excitation system. The exciters provide DC current through the generator rotor poles to generate the rotating magnetic field for the generators and are also used to control generator voltage output and volt-ampere reactive. The exciters have sophisticated computer hardware and software to match real time demand by monitoring operating parameters and making required adjustments for the generator. The existing excitation control system (EX 2000) is obsolete and past end of expected life; the installed circuit boards are 18 years old, with individual obsolete components having 12- to 15-year life expectancies. Project implementation will be coordinated with the LCI upgrade project, thereby obviating the need for a separate outage. Project implementation will reduce the risk of an unplanned unit outage and result in continued reliable operation of the unit;

- Zeeland Phase 2 Steam Turbine Building Roof Replacement ($600,000). The scope of project is to replace the roof on the building which houses the steam turbine. The building roof is in poor condition and requires replacement. The condition of the roof not only poses a health hazard but also poses a potential equipment hazard should any of the falling insulation make its way into plant equipment. The implementation of this project will increase plant safety and reduce equipment reliability risk; and

- Thirteen additional projects at Zeeland totaling $2.799 million support reliability and operations, with each project representing $550,000 or less in expenditures. These projects include chemistry lab upgrades, installation of fast acting fuel gas shutoff valves, replacement of the continuous emission monitoring system, gas turbine control valve upgrade, base outage capital, and various other small projects.

<u>**Jackson**</u>

Q. Please explain the Company's projected investment for the 12-month bridge year ending December 31, 2020 and 12-month test year ending December 31, 2021 for Jackson.

A. The Company plans to invest $24.644 million in 2020 and $16.345 million in 2021 at Jackson, as shown on Exhibit A-12 (SAH-3), Schedule B-5.2 page 2, line 36, columns (f) and (j), respectively. This will be facilitated by overhaul outages in spring and fall of 2020 and 2021. The Company has a LTSA with GE to cover many reliability issues at Jackson.

Q. What is the basis for the projected $24.644 million capital investment in 2020?

A. The projected $24.644 million capital investment in 2020 will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. Those projects which are greater than $1 million are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 8, lines 10 through 14. The basis for these projects is described below:

- Jackson LTSA ($10,600,000). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Jackson;

- Jackson LTSA Extra Work ($1,200,000). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Jackson;

- Turbine Control System Replacement ($3,265,000). This project will replace the existing control system with new control systems technology and architecture. The existing GE Mark V control system was installed in 2002, has had minimal upgrades since its original installation, and is at end of life. Turbine control systems require periodic updating to maintain reliability and to minimize the vulnerability to intrusion;

- Jackson Stack. ($1,500,000). This project will increase the stack height by 35 feet. The dispatch of the Jackson plant in the MISO energy market has historically been limited through a dispatch adder to ensure compliance with the Company's air permit. The Company has applied for and has received a revised air permit from the EGLE to increase the 12-month rolling NO_x emissions from the Jackson plant. Approval of that revised air permit was predicated on increasing the stack height by 35 feet from the existing height of 105 feet. The revised air permit increases the allowable 12-month rolling NO_x emissions limit and results in a reduction to the dispatch adder for the Company's offer in the MISO energy market. This will result in increased capacity factor, all else being equal, and an economic benefit to customers; and

- Jackson Warehouse ($4,400,000). This project will construct a new warehouse at Jackson. A new warehouse will provide a central location for plant inventory and tools storage as well as provide an adequate work space with adequate lighting, electrical, and compressed air for combustion engine maintenance. In addition, the warehouse will enable the plant to load/unload shipments via overhead hoist and fork truck without interfering with plant operations, as well as traffic flow in and around the plant. Combustion engine maintenance is currently performed in the steam turbine bay due to the availability of the overhead crane, a practice which is becoming less practical due to more frequent plant operation and, as a result, increased maintenance based upon operating hours. Further, the existing facilities are not adequate to load or unload heavy shipments of large pumps and combustion engines, necessitating the use of outside contractors to perform these activities.

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

- Jackson Circ Pump and Aux Circ Motor Overhauls ($655,000). Motors and pumps are due for overhauls based upon operating hours. The 'B' & 'C' pumps are planned to be completely overhauled in 2020. Both pumps have known operational issues with major cavitation pitting. The 'A' pump was overhauled in 2019 and major cavitation was found in that pump too. The aux motor will also be swapped out with the new spare during this outage. These three pumps are critical to the safe and reliable operation of the plant;

- Jackson RO Resin tank capacity ($585,000). The scope of this project is to replace the 3" portable resin tank connections with larger size to allow for use of 48 cubic foot tanks, purchase and install 12 new larger resin tanks, purchase first fill of the resin tanks, and purchase hoses to connect the new resin tanks. The plant was designed and built based on capacity factor of 48%, however, because of increasing demand, changes in market, and increases to air permitting, the plant is expected to run closer to an annual 60% capacity factor, upwards of 80% during peak season, and for longer continuous runs. As a result of this change, the existing water treatment system was upgraded to provide adequate water capacity, however a sub component of this system needs to be upgraded to take full advantage of the additional RO capacity. The resin tanks currently are 42 cubic feet in capacity each with 3" hose connections to the water header. In order to achieve full 750 gallons per minute of water generation, the resin tanks must be upgraded to 48 cubic foot capacity with 4" hose connections. Originally this would have been covered under the LTSA for maintenance of the RO system by Evoqua, but the contract was renegotiated during execution of the RO expansion project. This resulted in lower monthly O&M costs for the contract but pulled out many costs that could be capitalized. This project would increase the water production capability from 525 gpm to 750 gpm, and would allow for adequate water creation to run the plant in heat rate mode at all times. Heat Rate Improvements enable the plant to run in heat rate mode versus water conservation mode resulting in a 150 Btu/kWh improvement; and

- Sixteen additional projects at Jackson totaling $2.439 million, with each individual project representing $500,000 or less in capital expenditures. These projects include replacement of oil/water separator, major motor and pump overhauls, base outage work, glycol pump rebuild, and replacement of small valves, instrumentation, tools, equipment, pumps and motors.

Q. What is the basis for the projected $16.345 million capital investment in 2021?

A. The projected $16.345 million capital investment in 2021 will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. Those projects which are greater than $1 million are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 9, lines 22 through 24. The basis for these projects is described below:

- Jackson LTSA ($10,600,000). 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 Jackson plant is comprised of nine generating units. Units 1 through 6 are GE Model LM6000PC Gas Combustion Turbine-Generators ("CTG") each with a HRSG attached to the exhaust of the Combustion Turbine. Unit 7 is a GE Model Frame 7EA CTG with a HRSG, Units 8 and 9 are GE Steam Turbine-Generators powered by the steam created from the 7 HRSGs. 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, address service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if we execute the normal planned maintenance and inspections according to the recommended schedules, we will mitigate unexpected pre-mature failures of the equipment. This will help us maximize availability and, as a result, optimize our customer value for the site. Normal maintenance will ensure we have continued reliable operation of the units;

- Jackson LTSA Extra Work ($1,850,000). 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 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; and

- BFP Automatic Recirculation Control ("ARC") Valve replacement ($1,160,000). This project will replace the ARC valves for all three BFPs feeding the plants HRSGs. The static ARC valves will be replaced with pneumatic control valves wired into the DCS. The existing valves are considered severe duty valves, do not allow efficient operation of the BFPs, and require frequent maintenance. The inefficient BFP operation not only results in more frequent maintenance on the pumps but also increased station power. The ARC valve replacements will result in reduced O&M expense, reduced station power, and increased BFP operational control.

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

- Jackson Cooling Tower Maintenance Platforms ($500,000). The scope of this project is to install permanent grating in each cooling tower cell to allow for access to the equipment. This project will also install a fall restraint system to eliminate the fall hazard in the confined space to allow the cooling tower cell to be reclassified as a "Non-Permit" required confined space. The plant utilizes eight Main Cooling Tower Cells and two Auxiliary Cooling Tower Cells to provide cooling water for the plant operational processes. Multiple times each year, access is required to perform maintenance on the gearboxes, shafts, and fan blades that are located within the upper portion of the cooling tower cell. Due to the inherent design of the cell, the space has been classified as a Permit Required Confined Space because of the fall hazard that cannot currently be mitigated. As a result, the plant must provide a confined space rescue team while personnel are in the space. Due to the small staff at the plant, an outside contractor must be used to provide the rescue team. This incurs added cost to maintenance being performed and limits the work timing to the availability of the contractor's resources. During summer months when all cooling tower cells are required, the loss of a main cooling tower cell can result in plant derate of 15 to 20 MW due to inadequate heat removal from the steam turbine condensers. Loss of an aux cooling tower cell would increase the heat rate of Units 1 through 6 as the air inlet temperature of the Combustion Turbines ("CTs") would not be able to be cooled to the optimal range. The benefits associated with implementation of this project include the performance of maintenance without an external rescue team cost and their associated schedule limitations. Project implementation would also eliminate the fall hazard potential. Finally, the project implementation will support increased plant availability and reliability;

- HRSG Duct Burner Upgrade ($300,000). This multi-year project will restore the long-term reliability of the HRSG duct burner systems on the seven generating units which are equipped with a HRSG. Each HRSG is equipped with a natural gas duct burner system which provides additional heat input into the HRSG to create additional steam power during electrical system peaks. The existing duct burners are original plant equipment, frequently fail, and result in increased O&M expense and missed energy market opportunities; and

- Eleven additional projects at Jackson Generating Station totaling $1.935 million, with each individual project representing $500,000 or less in expenditures. These projects include base outage work, major motor and pump overhauls, circulating pump and auxiliary circulating motor overhauls, HRSG valve rack replacement, cooling tower maintenance platforms, and small valves, instrumentation, tools, equipment, pumps, and motors.

<u>**Combustion Turbines**</u>

Q. What are the forecasted generating plant capital expenditures for the CTs included in Exhibit A-12 (SAH-3), Schedule B-5.2 page 2, line 43?

A. There is no planned capital investments for the CTs in 2020 or 2021. Decommissioning of the CTs began in 2019 and is projected to be completed in 2020.

HYDRO UNITS

Q. Please explain the Company's projected capital expenditures for the 12-month bridge year ending December 31, 2020 and 12-month test year ending December 31, 2021 for the Hydro Units.

A. The Company plans to invest $15.073 million in 2020 and $31.542 million in 2021 in the Hydro Units, as shown on Exhibit A-12 (SAH-3), Schedule B-5.2, page 3, line 57, columns (f) and (j), respectively.

Q. What is the basis for the projected $15.073 million capital investment in 2020?

A. The projected $15.073 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. Those projects which are greater than $1 million are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 8, lines 15 through 18. The basis for these projects is described below:

- Alcona Emergency Spillway ($1,890,000). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Hydros;
- Five Channels Electrical Safety Project ($1,631,000). The purpose of this project is to remediate all unsafe and/or exposed electrical equipment. This electrical safety upgrade will correct for unsafe/exposed Five Channels equipment, including the replacement of obsolete generator control/metering and protective relays, replacement of voltage regulators and voltage regulator controls, replacement of outdated bus, potential transformer insulators, and disconnects with new switchgear, elimination of arc flash and shock hazards, and evaluation/upgrade of all ground connections and cable/wiring. Construction for this dam began in 1911 and completed in 1912. Five Channels Dam has two units each constructed with Allis Chalmers Horizontal Francis turbines with 35-foot head and GE 3 megawatt 180 rpm 2500 volt generators;
- Hardy Auxiliary Spillway Remediation ($1,000,000). This project spans 2020 and 2021 and its basis is included in my discussion of 2021 capital projects for Hydros; and
- Webber Unit 1 Overhaul ($1,690,000). The scope of this project is to remove and refurbish all three turbine shafts, replace the three pairs of runners, inspect the gate cases, and install new bronze runner seals. In addition, all wicket gate bushings and wooden Lignum Vitae journal bearings will be inspected and replaced if needed. The babbitted journal and thrust bearings will also be inspected and rebabbitted if required. Finally, a full train alignment will be completed. Webber Unit 1 is a 1907 horizontal six runner unit. The runners are original equipment and are now in excess of 110 years old. This unit has never been overhauled or subject to major repairs except for the wicket gate work in 2012. System Engineering and site personnel have assessed the material condition of the runners and found the system to be degraded beyond repair. The blade sections are missing in several sections, are bent, and have thinned beyond acceptable industry standards. As the blades continue to deteriorate, the rotating equipment elements become out of balance, resulting in excessive stress on all of the bearings and shafts. The current condition of the unit limits its operation and necessitates the diversion of river flow to the spillway based upon flow conditions, resulting in increased degradation in this

area downstream of the dam. In addition, because the spillway operation is not automated, there is some variation in downstream river flow during periods of flow change in the river. The completion of this overhaul will reduce use of the spillway, restore unit reliability, and increase both unit efficiency and capacity factor, resulting in increased electrical output. This project began in 2019 with a projected capital expenditure of approximately ($800,000).

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

- Mio Middle Embankment Erosion Protection Project ($600,000). The scope of this project is to engineer and construct rip rap downstream of the auxiliary spillway along the toe of the middle embankment. The model of auxiliary spillway flows with Probable Maximum Flood ("PMF") Supplement No. 2 suggests that flow velocities are high enough to initiate erosion at the toe of the middle embankment and the Part 12 independent consultant recommends that risk reduction measures be evaluated, and an option selected and constructed to protect the middle embankment from erosion due to auxiliary spillway flows. Erosion at the toe of the middle embankment is a key component in the failure of PMF 2.12 Failure of the Auxiliary Spillway due to Downstream Erosion during a Major Flood Event (at or near PMF). The installation of an erosion protection feature at the toe of the middle embankment would increase the factor of safety for PMF 2.12, therefore reducing the likelihood of a dam failure during activation of the Auxiliary Spillway;

- Hardy Crest Roadway Replacement and Compaction ($500,000). The project is being executed to eliminate a dam safety and public safety risk to the roadway along the dike crest. There are voids occurring along the dike crest and roadway that develop into pot holes and washouts, impacting safe travel and dam safety monitoring. The team evaluated roadway improvement options to determine the optimal repairs that would mitigate the safety risk. Engineering and design planning will be performed in 2020. In 2021 we will be awaiting FERC approval of the design recommendations. The final execution of the roadway replacement is scheduled for 2023 and the overall project cost is expected to total $5,800,000 from 2020 through 2023;

- Cooke Governor Replacement ($875,000). The scope of this project is to replace the governors with a system that would contain much less oil that could be captured in the event of a spill before entering the river. The Cooke Dam Governor controls utilize a large quantity of oil that has no containment or spill provisions to prevent an oil spill from entering the AuSable River. The new governor units only contain several gallons of oil, resulting in reduced risk to the environment and more precise control of the unit;

- Webber Unit 1 Generator Rewind ($580,000). The scope of this project is to rewind the Webber Unit 1 generator stator and field poles. As part of the System Health Condition Assessment Program, the Webber 1 generator was electrically tested, and the test results revealed that the generator is in poor condition and in need of a rewind. A failure of the generator would result in a forced outage and result in substantial generation loss and poor license compliance. The generator rewind will be performed concurrent with the Webber Unit 1 overhaul to minimize customer impact. This work is a continuation of the project which began in 2019 at a projected capital expenditure of $849,000;

- Mio Spillway Hoist Replacement ($630,000). Due to a recent failure of a hoist chain that snapped and bent the A frame of a traveling hoist, all installed Hydro hoists were evaluated in 2018. The hoists that were found deficient or degraded are being replaced to ensure safe operation. Project completion will allow the hoist to perform the required work safely and reliably;

- Rogers Spillway Chamber Fill ($545,000). The scope of this project is to fill the chambers inside the spillway with concrete. The purpose of this effort is to add mass to the structure and improve the stability of the structure during a flood condition. The Rogers spillway was rehabilitated prior to FERC's requirement to perform the chamber fill. The FERC inspector indicated the need to perform this work during his last inspection;

- Five Channels Governor Replacement ($695,000). The scope of this project is the installation of a new, low volume governor. The existing governor is a high-volume LP system with a large oil reservoir. As a result. the risk of accidental oil release to the waterway is increased. The implementation of this project will reduce environmental risk at this facility and reduce exposure to spills/cleanup costs; and

- Forty-seven projects specific to Hydro totaling $4.437 million with each individual project representing $400,000 or less in capital expenditures. These projects include Mio Unit 2 bearing replacement, Loud and Cooke trash rack ergonomic project, Foote Spillway Chamber Fill, Five Channels headgate repairs, spillway hoist replacement and corewall remediation, Five Channels and Cooke powerhouse upgrades to pass PMF, Alcona core wall remediation, and small tools, valves, and instrumentation.

Q. What is the basis for the projected $31.542 million capital investment in 2021?

A. The projected $31.542 million capital investment in 2021 will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. Those projects which are greater than $1 million are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 9, lines 25 through 32. The basis for these projects is described below:

- Five Channels Corewall Remediation ($2,050,000). The scope of this project is to remediate the Five Channels Corewall by raising it to the elevation needed from the PMF flows. The PMF flows will be modified depending on the outcome of Alcona risk informed decision making ("RIDM") project, thereby impacting the necessary corewall height. The corewall is currently in poor condition and it is being inspected periodically by Dam Safety Staff;

- Hardy Auxiliary Spillway Remediation ($8,000,000). The Hardy Auxiliary spillway is deficient, deteriorated, and requires replacement. The last Part 12D Inspection of the dam in 2014 resulted in a recommendation for remediation and the associated design was postponed due to the Oroville Dam Spillway incident in 2017. In May 2019, an options study was performed which considered and evaluated multiple spillway alignments, inlet structures, and conveyance systems. The options study determined that a labyrinth overflow weir or gated spillway structure was preferable for passing the design discharge. The options study considered seven alternative replacement options, including doing nothing and selling the asset. The various options included various alignments, inlet structures, energy dissipaters, conveyance structures, and Inlet Design Flow Requirements. Based upon the options study, the chosen alternative will satisfy the compliance requirements of the FERC license. The chosen alternative follows industry standards to keep the discharge away from the embankment, powerhouse, and highest portion of the dam. Design of the chosen alternative along with evaluation of a retirement option will begin in January 2020 with a projected capital expenditure of $1.000 million in 2020 and $8.000 million in 2021. A new spillway will address various PMFs at the site and FERC is requiring either repair or replacement of the spillway;

- Loud Training Wall Replacement ($2,200,000). The scope of this project is to replace the training wall. In 2018, the third-party condition assessment consultant identified that the underwater portion of the training wall was severely deteriorated and the whole wall is bowing significantly. The dive inspection observed that cracking, separation at the base from the spillway apron, and leaning of the wall indicate the concrete reinforcement may be the only resistive force providing stability of the wall system. Replacing the training wall would reduce the probability of failure of the training wall, its adjacent structures, and the overall dam operations. The rehabilitation of the wall was considered as a possible alternative, but it was determined that the existing wall was too deteriorated for restoration. The use of an updated H&H study would reassure that the new design is adequate. Design engineering shall include performing an H&H Study for the Au Sable River that includes creating the tailwater rating curve for multiple flow levels up to PMF;

- Mio Electrical Safety Project ($2,300,000). The scope of this project is the replacement of all electrical equipment with new modern equipment. This would include the installation of new outdoor switchgear, station power high side and low side disconnects, and distribution. The primary focus of this project is employee safety by reducing exposure to open electrical equipment, thereby reducing arc flash risk;

- Hodenpyl 1 Generator Rewind ($1,579,000). The scope of this project is the rewind of the Hodenpyl Unit 1 generator stator and field poles. The Hodenpyl Unit 1 stator and field pole windings are in poor condition and are at risk of failure. A failure would result in a prolonged forced outage. Fixing the generator coincident with the Hodenpyl main cable replacement outage would mitigate the failure modes identified and will prevent unexpected failures and prolonged forced outages;

- Hodenpyl spill gate and head gate hoist ($1,625,000). At Hodenpyl there is only one hoist that operates both the caterpillar spill tube gates and the head gates. The original hoist is in poor operation, it has two different reels for the different gate chain sizes required for the two different types of gates. There are potential pinch points, ergonomics concerns with the hooking and dogging of the chains. Evaluate the hoist for adequacy, ergonomics, and redundancy. This project is tied to the risk evaluation of the initiation of the emergency spillway at Hodenpyl. The spill tubes have enough capacity to pass the Inflow Design Floods at Hodenpyl but if we lose the only hoist on site, we may not be able to get a crane on site during a storm event, allowing the pond to fill and potentially initiate the emergency spillway. Therefore, the redundancy for both the head gate and caterpillar gates is necessary. The risk reduction measures from the emergency spillway study need to be incorporated into choosing the best alternate to reduce overall site risk;

- Webber Downstream Training Wall Repair ($2,300,000). The scope of this project is the replacement of the downstream training wall between the tailrace and spillway. The need to perform this repair was identified during a FERC required 12D inspection that was performed in 2011. The training wall showed signs of significant concrete deterioration and needs to be repaired. This project work began in 2019 with projected capital expenditures of almost $200,000; and

- Croton Units 3 and 4 governor replacement ($1,121,000). The scope of this project is the replacement of the existing governors with new, low volume governors. The existing governors are high-volume LP systems with large oil reservoirs. As a result, the risk of accidental oil release to the waterway is increased. The new governors will reduce environmental risk to the facility and reduce exposure to spills/cleanup costs.

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

- Alcona Emergency Spillway ($790,000). Due to recent dam failures with grass lined spillways, FERC is requiring that all existing grass lined spillways be evaluated. From evaluations, the spillway experiences head cutting during a once-in-10,000-year storm event which affects the safety of the structure. FERC requires the design flow rate for hydroelectric dams to be the PMF. This project will address this issue with modifications to the plant and/or spillway. The capital project spans 2020 and 2021. The project team is working with RIDM to determine the design criteria based on risk for the spillway. In 2021 they will continue to work on the supporting studies such as the Au Sable River PMF and the 2D auxiliary erosion modeling. In addition, they continue to study the relationship between dam safety and the interplay between PMFs. There will also be additional studies performed to understand what the quantitative risk assessment is taking into account uncertainties and sensitivities for different conditions. The primary objective of this project is to provide public and employee safety by preventing dam failures;

- Rogers Unit 4 Generator Rewind ($814,000). The scope of this project is the rewind of the Rogers Unit 4 generator stator and field poles. The Rogers Unit 4 stator and field pole windings are in poor condition and could fail at any time. A failure would result in a prolonged forced outage and result in substantial generation loss. This project will result in increased unit reliability;

- Hardy Emergency Gate Replacement ($580,000). The scope of this project is the design and installation of a new emergency head gate which satisfies the Army Corps of Engineers Type A standards. Type A standards are applicable to hydraulic steel structures which are used for emergency closures and are subject to severe dynamic (hydraulic) loading or are normally submerged where maintenance is difficult. Based upon a gate inspection, condition assessment, and factor of safety analysis for the emergency headgate, it was determined the gate was overstressed with both static and dynamic loads. In order for the gate to act as a "double-block-and-bleed" with the unit headgate and static loads of the head, the emergency head gate was rehabilitated in 2019, so the spill tube project could progress. The rehabilitated emergency head gate has operational restrictions: (1) it can only be used in conjunction with the unit head gate, and (2) it cannot be used on dynamic loads. The mitigation efforts for PMF 2.10 "Failure of Penstock Expansion Joint" include dropping down the emergency head gate in an emergency situation, which would subject the emergency head gate to dynamic loads. Because of the operational restrictions on the emergency head gate, it would not be able to be used as a true "Emergency Head Gate" and could result in an uncontrolled release of the reservoir. Additional situations in which the emergency head gate is needed are a runaway unit or a unit head gate failure. The new gate would require less maintenance compared to rehabbing a 100-year-old gate and would be able to handle the dynamic loads necessary of that of an emergency gate; thereby reducing the risk of an uncontrolled release of the reservoir. The emergency head gate would also be able to be used as a mitigation effort for the PMF described above;

- Croton Unit 2 Generator Rewind ($900,000). The scope of this project is the rewind of the Croton Unit 2 generator. On September 15, 2019 the Generator Y Phase shorted to ground. As a result of failed generator windings, the unit is out of service. This project will restore operation of the unit;

- Alcona Unit 2 Bearing Replacements ($466,000). The scope of this project is the replacement of the Alcona Unit 2 radial and thrust bearings, and subsequent unit alignment. Alcona dam is the only dam in the Consumers Energy Hydro fleet that is not able to throttle the spill flow. If the generating units are not available, flow in the river must be maintained by cycling the spill valves between full open and full closed, potentially creating river flows that are not compliant with the operating license. The implementation of this project will increase unit reliability and support the ability to operate the river in a compliant manner;

- Alcona Unit 2 Wicket Gate Refurbishment ($420,000). The scope of this project is the refurbishment of the 20 vertical wicket gates. The wicket gate upper and lower bushings are worn and require replacement. The loose wicket gates allow water to leak by and pass through the unit without generating electricity. In addition, the regulating ring brass sliders and the wicket gate link bushings require replacement and the servos that operate the regulating rings require rebuild; including arm bushing replacement. This project will be implemented in coordination with the project to replace the Alcona Unit 2 radial and thrust bearings as the disassembly and reassembly requirements are the same and, as a result, allow for the avoidance of approximately $250,000 in additional capital expenditures. Five Channels Spillway Hoist Replacement ($863,000). Due to a recent failure of a hoist chain that snapped and bent the A frame of a traveling hoist, all installed Hydro hoists were evaluated. The hoists that were found deficient or degraded are being replaced to ensure safe operation. Project completion will allow the hoist to perform the required work safely and reliably; and

- Forty-eight projects specific to Hydro totaling $5.534 million with each individual project representing $300,000 or less in capital expenditures. These projects include Alcona, Cooke, and Loud powerhouse window replacement, Caulkins bridge electrical safety – station power replacement, Cooke Units 1 through 3 headgate rehabilitation project, Hardy dam penstock fill valve replacement, Caulkins Bridge Unit 1 headgate fill and openers, Hodenpyl downstream wall, Mio left retaining wall replacement, Rogers middle embankment toe reverse filter and drain, new Rogers dam heated storage building, Rogers PMF Study improvements, and small tools, valves, and instrumentation.

LUDINGTON

Q. Please explain the Company's projected capital expenditures for the 12-month bridge year ending December 31, 2020 and 12-month test year ending December 31, 2021 for the Ludington Plant.

A. The Company plans to invest $22.682 million in 2020 and $21.892 million in 2021 in the Ludington Plant, as shown on Exhibit A-12 (SAH-3), Schedule B-5.2, page 3, line 64, columns (f) and (j), respectively. These capital investments will be facilitated by completion of the major overhaul on Unit 3 in May 2020, various short outages in 2020 and a spring outage in 2021.

Q. What is the basis for the projected $22.682 million capital investment in 2020?

A. The projected $22.682 million capital investment in 2020 will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. Those projects which are greater than $1 million are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 8, lines 19 and 20. The basis for those projects is described below:

- Ludington Upgrade and Overhaul ($12,707,000). The last of six units, Ludington Unit 3, is being upgraded to a new, higher efficiency design. The overhaul began on May 13, 2019 and will replace the original 388 MVA unit with a new Toshiba 455 MVA design. All major components of the generating/pumping unit have been redesigned and will be replaced - water turbine (aka "runner"), wicket gates, generator, and stator. This new equipment will be manufactured using materials intended to lengthen operating life, reduce operating costs, and improve operating efficiencies. The final upgrade is scheduled to be complete in May 2020 and will result in the capability to generate more energy with the same pond level, resulting in greater capacity value and increased energy value; and

- Ludington 16-424 HVAC Replacement ($4,371,000). The high-level scope for this project includes a complete replacement and upgrade of the HVAC systems on the Ludington site with few exceptions. In December 2014 Century A&E performed a study of the HVAC systems at the Ludington facility. The results of that study revealed that a major equipment replacement and upgrade was required to restore the proper operation of the HVAC systems in several areas. The areas included the administration building, air-conditioned areas within the powerhouse, and the powerhouse turbine areas (heated and ventilated only). Implementation of the project will restore the HVAC systems necessary to safely operate the plant for many years to come.

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

- Powerhouse Roof Wearing Surface and Weather Proofing Replacement ($668,000). This project spans 2020 and 2021 and its basis is included in my discussion of the 2021 capital projects for Ludington;

- Replacement of the Ludington Depression Air Compressors ("DAC") 1 and 2 ($335,000). This project spans 2020 and 2021 and its basis is included in my discussion of the 2021 capital projects for Ludington;

- Replacement of the Ludington Plant Station Air Compressors ("SACs") ($360,000). This project spans 2020 and 2021 and its basis is included in my discussion of the 2021 capital projects for Ludington;

- Replacement of the Ludington Plant Data Acquisition System ("DAS") ($661,680). The scope of the project is to replace the existing Allen Bradley single Network with Emerson Ovation three network systems, thereby limiting single network exposure to 780 MW each. Each network would consist of one Redundant Processor set, Redundant Power Supplies, Redundant Network Switches. The existing DAS system currently uses Windows Server 2008 and Windows 7 operating systems. Microsoft has announced that it will be officially ending its support for Windows Server 2008 and Windows 7 on January 14, 2020. The replacement equipment was purchased in 2019, engineering and planning will continue throughout 2020 and the installation will occur during the major pond outage in 2021;

- Design and Install Barrier Net – pursuant to the Adaptive Management Process ("AMP") ($542,000). This project spans 2020 and 2021 and its basis is included in my discussion of the 2021 capital projects for Ludington;

- Replace 480V Dike Load Centers ("DLCs") ($421,900). This project spans 2020 and 2021 and its basis is included in my discussion of the 2021 capital projects for Ludington;

- Replace Barrier Net Panels ($408,000). This project spans 2020 and 2021 and its basis is included in my discussion of the 2021 capital projects for Ludington; and

- Eighteen additional projects at Ludington totaling $2.208 million, with each individual project representing $510,000 or less in expenditures. These projects include reservoir liner replacement, lower penstock expansion joint chamber waterstop replacement, pressure regulation of main cooling water header, thrust bearing pad for capital spares, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected $21.892 million capital investment in 2021?

A. The projected $21.892 million capital investment in 2021 will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. Those projects which are greater than $1 million are presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 9, lines 33 through 37. The basis for these projects is described below:

- Ludington Upgrade and Overhaul ($2,040,000). The project scope for 2021 consists of the final closeout of the upgrade and overhaul of the six Ludington generating units. All six units are being upgraded to a new, higher efficiency design. The overhaul replaced the original 388MVA units with a new Toshiba 455 MVA design. All major components of the generating/pumping units were redesigned and replaced - water turbine (aka "runner"), wicket gates, generator, and stator. The new equipment was manufactured using materials intended to lengthen operating life, reduce operating costs, and improve operating efficiencies. For Ludington Units 1 and 6, the pony motors which are unique to these two generating units were rewound as part of the upgrade. These upgrades resulted in the capability to generate more energy with the same pond level, resulting in greater capacity value and increased energy value;

- Powerhouse Roof Wearing Surface and Weather Proofing Replacement ($3,380,000). The scope of this project includes engineering of the demolition, disposal, and replacement of the concrete wearing surface and waterproofing. This project will begin in 2020 with engineering and material procurement, with installation in 2021. The Ludington Plant powerhouse roof wearing surface and waterproofing has deteriorated and needs to be replaced. The powerhouse roof has only had minor repairs since the plant was originally constructed. Currently there is water seeping through the roof and leaking onto electrical equipment. Failure to remedy this situation exposes the electrical equipment to water intrusion and premature failure;

- Design and Install Barrier Net – pursuant to the AMP ($1,916,800). This project is a multi-year project which is being implemented in accordance with the Ludington Relicensing Settlement Agreement, Appendix B. The Ludington Plant barrier net requires studies and improvements over the next five years pursuant to the agreement. The objectives of this project are to optimize barrier net operations and maintenance functions to reduce fish entrainment mortality during pumping and generation, consistent with safety considerations; optimize barrier net design and placement to improve barrier net performance, utilize data from fish community characterization studies to help inform and optimize barrier net design and operations; utilize the results of technology reviews to improve barrier net performance through potential changes in design or deployment; and the implementation of fish entrainment prevention technologies;

- Ludington Reservoir Liner Replacement ($6,610,000). The scope of this project is to remove the existing mastic and installing a new layer of mastic on top of the asphalt liner. The mastic liner is the top layer of the asphalt liner of the reservoir at Ludington Plant. Over the years of operation, the asphalt liner has become more brittle. Numerous cracks, holes and spalls have been repaired as part of the asphalt liner inspection and repair program. Removal and installation of a new liner and replacing specific distress features that threaten impermeability of the asphalt liner will extend the current asphalt liner design life another 25 years and ensures that the reservoir can be safely used for generation and pumping operations. If the mastic liner replacement work is accomplished prior to 2023, the upper 6 inches of the asphalt liner of the entire reservoir would need to be replaced by 2027. Further, if the asphaltic liner is not maintained in accordance with our FERC license, the full pond level will not be usable, and generation will be threatened. This project will be accomplished simultaneously with the major maintenance project to remediate the erosion gullies, as discussed later in this direct testimony; and

- Replace Lower Penstock Expansion Joint ("LPEJ") Waterstop ($1,655,777). The scope of this project is replacement of the LPEJ waterstop and potentially dewatering the surrounding groundwater, depending on which option is chosen. The options being evaluated include installation of a new waterstop in place of the current one, the installation of an interior surface seal on top of the current waterstop, and installation of an exterior surface seal. The engineering study will be performed in 2020 with project implementation to begin in 2021. 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 reduces current risk of a potential failure mode and supports Ludington unit generation well into the relicensing period.

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

- Replacement of the Ludington DACs 1 and 2 ($935,000). The scope of this project is the replacement of both existing DACs with higher capacity units with remote start capability. The current DACs are incapable of providing sufficient capacity to maintain system pressure during periods when three or more of the overhauled Ludington generating units are in operation. In addition to the capacity limitation, the reliability of the DACs has continued to degrade. This situation will continue to worsen as system demand increases following additional generating unit overhauls. Finally, the turndown ratio of the DACs is poor, they run continuously due to startup issues and no remote start capability, and each unit's station power need is approximately 1 MW in the unloaded state. Implementation of this project will result in improved compressor reliability, improved plant reliability, availability, and efficiency, and reduced O&M expense. This is a multi-year project with engineering/procurement being performed in 2020 and installation in 2021;

- Replacement of the Ludington Plant SACs ($479,000). The scope of this project is the replacement of the existing reciprocating SACs with 4-stage centrifugal units that will directly supply the DAC system with the station air being serviced through a redundant reducing station. The replacement SACs will feature higher pressure and flow to better support their intended function. The existing SACs are inoperable and, as a result, not available for service. The requisite Ludington station service air is temporarily being supplied by lower capacity rotary screw compressors that are located outside of the powerhouse. The inoperable SACs were also designed to serve as a backup to the DACs, however this redundancy does not currently exist and jeopardizes the DAC system as well. The current SACs cannot be effectively overhauled due to their degraded condition. Replacement of the SACs will restore full functionality to the SAC system including its backup support to the DAC system. This project will improve plant reliability, availability, and efficiency and at the same time, reduce O&M expense due to the elimination of the temporary rotary screw air compressor and, from time to time, the rental of diesel backup air compressors. This is a multi-year project with engineering/procurement being performed in 2020 and installation in 2021;

- Replace 480V DLCs ($530,400). The scope of this project is the replacement of the 20 480V DLCs over a 6-year period. 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 6-year period will provide high electrical system reliability and ensure FERC compliance;

- Replace Ludington EDG and Bus 4 ($637,500). The generator and related bus are both original equipment and have become a reliability risk. The system provides emergency power to the site to ensure the ability to be black start capable. Upon replacement, the unit will be maintaining its reliability for black start purposes. This project began in 2019 with a projected capital expenditure of $0.875 million for that work and the balance of this project was deferred to 2021 to align with the pond outage;

- Ludington - No load switches on exciter Power Potential Transformers ("PPTs") ($700,000). The scope of this project is the engineering, planning, procurement, and installation of no load switches between the Isolated Phase Bus and Automatic Voltage Regulator PPT such that they can be isolated under no load conditions. This implementation of this project will allow plant operations to isolate a generating unit from a main transformer bank to provide worker protection;

- Carbon Dioxide ("CO_2") fire protection system replacement ($610,000). The scope of this project is the replacement of the existing CO_2 systems with new fire protection equipment. Removal of the full CO_2 system and replacing it with an alternate system (water spray) for the oil and paint room on level C and the bulk oil room on level D. As part of the major unit overhauls, the CO_2 fire protection system in the generators is being removed. An accidental release of CO_2 in the powerhouse requires evacuation of all personnel until the air is checked and approved by the local emergency responders;

- Replace Barrier Net Panels ($420,240). The panels are a regulatory required system to minimize fish entrainment. The panel replacements are primarily time based. Ludington has extensive operating experience with these panels, which helps determine when a replacement is required. Similar funding amounts are included for both 2020 and 2021;

- Ludington Plant Annunciator Upgrade ($343,520). The existing plant annunciator panel technology is obsolete. Spare parts are becoming difficult to acquire, impacting annunciator reliability. Reliable plant annunciator systems are essential to ensuring equipment reliability and preventing significant equipment failures; and

- Eleven additional projects at Ludington Generating Station totaling $1.634 million, with each individual project representing $400,000 or less in capital expenditures. The projects include intake gate and gate house mechanical refurbishment, barrier net anchor pile replacement, and small tools, pumps, motors, valves, and instrumentation.

ADMINISTRATIVE AND OTHER

Q. Please explain the Company's projected capital expenditures for the 12-month bridge year ending December 31, 2020 and 12-month test year ending December 31, 2021 for Administrative and Other.

A. The Company plans to invest $2.395 million in 2020 and $3.384 million in 2021 in Administrative and Other, as shown on Exhibit A-12 (SAH-3), Schedule B-5.2, page 3, line 71, columns (f) and (j), respectively.

Q. What items are funded in Administrative and Other?

A. Items grouped under "Administrative and Other" include capital expenditures for business and engineering tools, and equipment. These expenditures will provide for more effective project implementation and support our continued effort to provide excellent service to our customers.

Q. What is the basis for the projected $2.395 million capital investment in 2020?

A. The projected $2.395 million capital investment will support several projects during 2020. There is one project which is greater than $1 million, and it is presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 8, line 21. The basis for this project is described below:

- Enterprise Project Management Office ("EPMO") Transformation—Enterprise Project Management Information System ($1,910,258). Expenditure for upgrading project management tools and methods, allowing better tracking and more effective project implementation. Specifically, the 2020 capital expenditure amount will implement the project management information system ("PMIS") which was chosen by the Company after proof of concept on the Ludington overhaul project as well as a request for proposal process which evaluated eight comparable products. The benefits of implementing the PMIS include resolution of an external audit finding, increased project management efficiency, and speed of delivery. The PMIS will provide the tools, technologies, and processes for project management to control the risks associated with delivering a large portfolio of capital projects valued well into the billions of dollars.

The basis for the other project to be completed during 2020 is below:

- Laptop and capital business tool purchases for Electric Engineering, Energy Supply, Environmental services, lab Services, Business Services, and Enterprise Project Management ($485,000).

Q. What is the basis for the projected $3.384 million capital investment in 2021?

A. The projected $3.384 million capital investment will support several projects during 2021. There is one project which is greater than $1 million, and it is presented on Exhibit A-12 (SAH-3), Schedule B-5.2, page 9, line 38. The basis for this project is described below:

- EPMO Transformation — Enterprise Project Management Information System ($2,899,015). Expenditure for upgrading project management tools and methods, allowing better tracking and more effective project implementation. Specifically, the 2021 capital expenditure amount will implement an analytics reporting tool which will leverage the Company's existing scheduling tools as well as the PMIS that the Company is implementing in 2020. The analytics reporting tool is a live reporting tool which will enable EPMO to understand performance and trends across all of its projects, obtain greater insight into cost and schedule metrics, and customize reports and portals to support the business.

The basis for the other project to be completed during 2021 is below:

- Laptop and capital business tool purchases for Electric Engineering, Energy Supply, Environmental Services, Lab Services, Business Services, and Enterprise Project Management ($485,000).

<u>COMPANY-OWNED SOLAR</u>

Q. Please explain the Company's planned investments in solar energy resources through the projected test year ending December 31, 2021.

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 Company's Proposed Course of

Action ("PCA") which included the addition of 1,200 MW of solar energy resources. The first 100 MW of incremental solar energy resources will support the Company's Renewable Energy Plan ("REP") and the balance of the solar energy additions (1,100 MW) will be financed outside of the REP reconciliation process. The Company's projected investment amounts are based upon Company ownership of 50% or 550 MW of the non-REP additions. Consistent with the Company's PCA and the 50% ownership allowance, the Company will add 150 MW of solar in 2022, 150 MW of solar in 2023, and another 250 MW of solar in 2024.

Q. How will the Company-owned solar energy resources be developed?

A. Consistent with the settlement agreement, the Company will conduct annual solicitations for the addition of 550 MW of Company-owned solar through 2024. The competitive procurement process will be administered by an independent third party as discussed by Company witness Troyer.

Q. Has the Company included any projected capital expenditure amounts for the addition of the solar resources in this case?

A. No. As discussed by Company witness Troyer, the competitive solicitation for the 150 MW of solar to be delivered in 2022 is still in process and, as a result, neither the level nor the timing of the investment amounts are well defined at this time. Company witness Myers discusses how the Company will account for any required investment amounts through the projected test period ending December 31, 2021.

Q. Does the Company have a projection of the timing and level of investment associated with the first tranche of Company-owned solar?

A. Yes. For planning purposes, the Company has projected a 2020 investment of \$62.741 million and a 2021 investment of \$125.442 million. The 2020 investment reflects 30% of the projected total investment for the Company-owned solar energy resources that will become commercially available in May 2022. The 2021 projected investment of \$125.442 million reflects 30% of the projected investment for the Company-owned solar energy resources that will become commercially available in 2022 as well as 30% of the projected investment for the Company-owned solar energy resources that will become commercially available in May 2023.

Q. How were the total projected investment amounts determined?

A. The total projected investment of \$209.7 million for both the 2022 and 2023 solar energy resources was based upon an estimated installed cost of \$1380/kW.

Q. Are you supporting any other projected capital expenditures for renewable energy in the test year ending December 31, 2021?

A. Yes. I am also supporting an Information Technology project, Renewables Supervisory Control and Data Acquisition ("SCADA") Overlay Project. The 2021 projected capital expenditure amount of \$0.813 million is reflected in Exhibit A-12 (JDT-3), Schedule B-5.3, and the 2021 projected O&M expense of \$0.022 million is reflected in Exhibit A-105 (JDT-2). This project is the design, procurement, installation, and commissioning of a SCADA overlay software application for the Merchant Operations Center ("MOC") and Renewable Generation Operations to view and control Lake Winds Energy Park, Cross Winds Energy Park, Grand Valley Solar, Western Michigan Solar, and Circuit

West Solar on a consolidated application pane. It will also provide the platform for monitoring and control of future wind and solar assets added to the generating fleet. The project will merge five separate different Renewable SCADA views (command and control functions, alarms, warnings, and key performance indicators for wind turbines and solar inverters) into a single operational and dispatch view through off-the-shelf Renewables SCADA overlay software. The project will also install on-premise servers and databases for daily operation and disaster recovery functions. Finally, the project will integrate the individual site native SCADA systems with the MOC. The project will bring the Renewables Generating fleet operations and dispatch up to industry standards, provide for safe, reliable, and available renewable generation, automate the NERC required reporting and associated changes to provide more efficient and higher quality data management.

Q. What is the basis for this project?

A. MOC is attempting to control the entire Consumers Energy Renewables generating fleet, currently 260 MW, from five separate SCADA interface screens and monitors. Another 525 MW of renewable energy will be added to the fleet by 2021 and, as I have previously discussed, another 550 MW of solar energy will be added through 2024 pursuant to the IRP. Attempting to manage the wind parks and solar inverters across multiple screens has the potential to introduce human error. In addition, the requisite regulatory and compliance reports for NERC generating availability data system (“GADs”) are manually generated and the reporting requirements are being expanded in 2020. The expansion of NERC GADs reporting requirements, coupled with the significant renewable energy asset growth, necessitates the automation of the reporting activity in order to avoid incremental O&M expense associated with manual preparation of the compliance reporting as well as management of the renewable assets by the MOC.

Q. Can you quantify the projected O&M expense avoidance associated with implementation of this project?

A. Yes. As a result of the increased NERC reporting requirements for wind turbines in GADS beginning in 2020, the annual savings associated with the automated reporting is estimated at $6,000 after project go-live. With respect to O&M expense avoidance for the MOC, this project assumes that the MOC would require an additional full time equivalent ("FTE") for each of the six shifts in 2021 to manage the Wind and Solar Renewable fleet without the consolidation of the SCADA views. As a result of the improved productivity and human performance by not having to switch and manage across multiple screens, this project will avoid $600,000 of annual expense based upon a cost estimate of $100,000 per FTE.

CAMPBELL UNITS 1 AND 2—AVOIDABLE/INCREMENTAL CAPITAL EXPENDITURES

Q. Please describe Exhibit A-69 (SAH-4).

A. Exhibit A-69 (SAH-4) illustrates the Company's unavoidable, avoidable, and incremental capital expenditures in 2021 at Campbell Units 1 and 2 under different scenarios in which those units are retired in 2024 or 2025. The Company considered capital expenditures for the following six scenarios in Exhibit A-69 (SAH-4):

- retirement of Campbell Unit 1 in 2024;
- retirement of Campbell Unit 2 in 2024;
- retirement of both Campbell Units 1 and 2 in 2024;
- retirement of Campbell Unit 1 in 2025;

- retirement of Campbell Unit 2 in 2025; and
- retirement of both Campbell Units 1 and 2 in 2025.

Q. Why has the Company included avoidable capital expenditures for Campbell Units 1 and 2 in this proceeding?

A. The Settlement Agreement approved by the MPSC in its June 7, 2019 Order in the Company's IRP, Case No. U-20165, required the Company to identify avoidable capital expenditures, both environmental and non-environmental, and avoidable major maintenance for Campbell Units 1 and 2 in 2024 and 2025 retirement scenarios. I will discuss avoidable major maintenance expense later in this direct testimony.

Q. Has the Company performed a new retirement analysis for Campbell Units 1 and 2 to support the avoidable capital expenditures and major maintenance expenses?

A. No. For purposes of this proceeding, the Company did not perform additional modeling to either support or reject the six retirement scenarios for Campbell Units 1 and 2 that I have previously discussed. For purposes of informing its decisions regarding generation capital expenditures and major maintenance expenses, the Company relied upon its currently approved IRP.

Q. When will Consumers Energy perform analysis addressing the six aforementioned retirement scenarios for Campbell Units 1 and 2?

A. Pursuant to the IRP Settlement Agreement, Consumers Energy will analyze those six scenarios in its next IRP filing, scheduled for June 2021. The IRP Settlement Agreement provides detailed direction regarding the analysis to be performed for that proceeding.

Q. What is the purpose of providing these avoidable and incremental capital expenditures?

A. The purpose of Exhibit A-69 (SAH-4) is to illustrate the capital expenditures that the Company could avoid in the projected test year ending December 31, 2021, under each of the six retirement scenarios for Campbell Units 1 and 2 in 2024 and 2025. However, as I have previously indicated, the Company is operating in accordance with its currently approved IRP and these illustrative avoidable capital expenditure amounts are purely hypothetical and should not be considered for purposes of determining the Company's revenue requirement deficiency. Companion Exhibit A-71 (SAH-6) addresses avoidable major maintenance expense for the same six retirement scenarios.

Q. What are avoidable capital expenditures?

A. Avoidable capital expenditures represent Campbell Unit 1 and Unit 2 capital expenditures that are included in the projected test year ending December 31, 2021, that the Company could theoretically forego making in the event the Company makes the decision to retire one or both Campbell units early. However, since the Company is operating in according with its Commission-approved IRP which reflects retirement of Campbell Units 1 and 2 in 2031, none of the capital expenditures identified in Exhibit A-69 (SAH-4) are practically avoidable.

Q. How did the Company determine which capital expenditures were avoidable?

A. For each of the six retirement scenarios for Campbell Units 1 and 2 in 2024 and 2025, the Company performed a review of its capital projects (both environmental and non-environmental) for the projected test year ending December 31, 2021 and made a determination as to whether the project would be required given the specific retirement scenario.

Q. Provide an example of an avoidable capital expenditure.

A. An example of an avoidable capital expenditure is the replacement of six boiler burner assemblies at Campbell Unit 2 in the projected test period ending December 31, 2021. The project to replace six of these burner assemblies in 2021 could be avoided in both a 2024 or 2025 Campbell Unit 2 retirement scenario. Although the new burners would improve combustion, reduce carbon in ash, and improve efficiency, their replacement would no longer be economic given a shorter period until Campbell Unit 2 retirement.

Q. Please explain the avoidable capital expenditures for the Campbell Unit 1 retirement scenarios for 2024 and 2025.

A. Exhibit A-69 (SAH-4), page 1, line 3, shows that under the 2024 Campbell Unit 1 retirement scenario, \$0.200 million of non-environmental capital could be avoided. Exhibit A-69 (SAH-4), page 2, line 3, shows that under the 2025 Campbell Unit 1 retirement scenario, \$0.200 million of non-environmental capital could be avoided. The \$0.200 million of avoided non-environmental capital for the 2024 and 2025 Campbell Unit 1 retirement scenarios is based upon projected capital of \$0.200 million for partial replacement of the superheat outlet pendant.

Q. Please explain the avoidable capital expenditures for the Campbell Unit 2 retirement scenarios for 2024 and 2025.

A. Exhibit A-69 (SAH-4), page 1, line 7, shows that under the 2024 Campbell Unit 2 retirement scenario, \$0.982 million of projected non-environmental capital and \$0.550 million of projected environmental capital could be avoided. Exhibit A-69

(SAH-4), page 2, line 7, shows that under the 2025 Campbell Unit 2 retirement scenario, \$0.550 million of projected non-environmental capital could be avoided. The \$0.982 million of projected non-environmental capital that could be avoided in the 2024 Campbell Unit 2 retirement scenario includes \$0.580 million for the overhaul of the condenser circulating water pumps and motors and \$0.402 million for the overhaul of the forced draft fan motors. The \$0.550 million of projected environmental capital that could be avoided for both the 2024 and 2025 Campbell Unit 2 retirement scenario was projected for replacement of burner assemblies.

Q. Please explain the avoidable capital expenditures for the Campbell Units 1 and 2 retirement scenarios for 2024 and 2025.

A. Exhibit A-69 (SAH-4), page 1, lines 11 and 15, show that under the 2024 Campbell Units 1 and 2 retirement scenario, the avoidable capital expenditures for each unit are the same as those under the individual unit retirement scenarios for 2024. Similarly, Exhibit A-69 (SAH-4), page 2, lines 11 and 15, show that under the 2025 Campbell Units 1 and 2 retirement scenario, the avoidable capital expenditures for each unit are the same as those under the individual unit retirement scenarios for 2025.

Q. Why weren't all of the capital expenditures for Campbell Units 1 and 2 for the six retirement scenarios determined to be avoidable?

A. Unavoidable expenditures represent Campbell Units 1 and 2 projected capital expenditures that are included in the projected test period ending December 31, 2021, that the Company must make even in the event the Company made a decision to retire one or both of the Campbell units early. Consistent with the Company's generation asset strategy, the Company will continue to operate its generating units in a safe and environmentally compliant manner through their retirement date.

Q. Provide an example of an unavoidable expenditure.

A. One example is the Campbell Units 1 and 2 SEEG Compliance – Closed Loop w/recirculation project. This project is due to begin in 2021 and would need to be performed even if Campbell Units 1 and 2 are selected for one of the early retirement scenarios.

Q. What are incremental capital expenditures?

A. Incremental capital expenditures represent capital expenditures at the Campbell site that are not currently included in the 2021 test year ending December 31, 2021, that the Company would need to add in the event the Company makes the decision to retire one or both of the Campbell Units 1 and 2 in 2024 or 2025. The practicality of the incremental capital expenditures is similar to that of the avoidable expenditures discussed above.

Q. Please explain the incremental capital expenditures for the 2024 retirement scenarios shown in Exhibit A-69 (SAH-4).

A. Exhibit A-69 (SAH-4), page 1, line 20, shows the incremental capital expenditure needed for Campbell Unit 3 for the projected test year ending December 31, 2021 if both Campbell Units 1 and 2 are selected for early retirement in 2024. In the projected test year ending December 31, 2021, the Company would make $4.000 million in incremental capital expenditures for this retirement scenario.

Q. Please explain the basis for this projected incremental capital expenditure amount for Campbell Unit 3.

A. In the hypothetical scenario in which the Company retired both Campbell Units 1 and 2 in 2024, the Company would need to accomplish detailed engineering in the projected test period ending December 31, 2021 for the separation of Campbell Units 1 and 2 from Campbell Unit 3. This work would be required to move forward with the separation beginning in 2022.

Q. Please explain the incremental capital expenditures for the 2025 retirement scenarios shown in Exhibit A-69 (SAH-4).

A. Exhibit A-69 (SAH-4), page 2, line 20, shows the incremental capital expenditure needed for Campbell Unit 3 for the projected test year ending December 31, 2021 if both Campbell Units 1 and 2 are selected for early retirement in 2025. In the projected test year ending December 31, 2021, the Company would make $0.300 million in incremental capital expenditures for this retirement scenario.

Q. Please explain the basis for this projected incremental capital expenditure amount for Campbell Unit 3.

A. In the hypothetical scenario in which the Company retired both Campbell Units 1 and 2 in 2025, the Company would need to begin engineering procurement, perform engineering support activities, cost studies, and reliability, maintainability, and safety engineering to be in a position to accomplish detailed engineering for the separation of Campbell Units 1 and 2 from Campbell Unit 3 in 2022 and move forward with separation in 2023.

Q. Does the Company project any incremental capital expenditures in the Campbell single unit retirement scenarios in 2024 or 2025?

A. No. As reflected on Exhibit A-69 (SAH-4), page 1, lines 4 and 8, and page 2, lines 4 and 8, the Company does not project incremental capital expenditures during the projected test period ending December 31, 2021.

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 our 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 witness Breining provides additional discussion in her direct testimony.

SECTION III

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, and Enterprise Project Management and Environmental Services organization.

Q. Please describe Exhibit A-70 (SAH-5), page 1, Generation Operation and Maintenance Expenses.

A. Exhibit A-70 (SAH-5), page 1, identifies the 2018 through 12 Months Ending December 31, 2021 Generation O&M expenses. Specifically:

- Column (a) identifies each O&M expense category;
- Column (b) identifies the Actual 2018 Generation O&M expense as $148,231,000;
- Column (c) identifies the Projected 2019 Generation O&M expense as $148,274,000;
- Column (d) identifies the Projected 2020 Generation O&M expense as $153,762,000; and
- Column (e) identifies the Projected 2021 Generation O&M expense as $166,793,000

<u>**HISTORICAL O&M EXPENSE**</u>

Q. Please explain how the 2018 Actual O&M expenses were developed.

A. The 2018 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the 2019 projected O&M expenses were developed.

A. The 2019 projected O&M expenses are based upon the Company's 9&3 forecast for 2019; 9 months of actual O&M expenses taken from Consumers Energy's internal accounting records and 3 months forecast O&M expenses.

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

A. Consumers Energy tracks the history and projects future maintenance needs of each 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, 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," "Karn Retention and Separation," and "Major Maintenance."

Q. What are Base O&M expenses?

A. Base O&M expenses are comprised of two categories – labor and non-labor. Labor is the primary component and 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; (3) tools; (4) cleaning supplies; (5) facilities; (6) security; and (7) road and grounds maintenance.

Q. Please explain how the projected 2020 bridge year and 2021 test year Base O&M expenses were determined.

A. Base O&M expenses for the projected bridge year ending December 31, 2020, and projected test year ending December 31, 2021 shown on Exhibit A-70 (SAH-5), page 1, line 1, columns (d) and (e), were determined by considering staffing levels and historical spending. Base O&M for the years 2018 through 2021 demonstrate average annual increases of 1.6%. Exhibit A-70 (SAH-5), 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 our employees, and to support the reliability of service to our customers, specifically, Environmental Operations and Major Maintenance. Exhibit A-70 (SAH-5), page 1, line 5, identifies Adjusted O&M expenses which are new as a result of the IRP settlement agreement. These expenses are required to safely and reliably operate Karn Units 1 and 2 through their May 2023 retirement.

Q. How was the average annual increase of 1.6% of Base O&M expense calculated?

A. The average annual increase was calculated by dividing 2018 Actual Base O&M expense of $108,466,000 (see Exhibit A-70 (SAH-5), page 1, line 1, column (b)) by the test year's projected Base O&M expense of $113,621,000 (see Exhibit A-70 (SAH-5), page 1, line 1, column (e)). Subtracting one from the quotient identifies the total percentage increase of 4.8% between 2018 and the 2021 test year. Dividing the total 4.8% increase by three (the periods of time between 2018 and the 2021 test year) gives the average annual increase of 1.6%.

ENVIRONMENTAL OPERATIONS

Q. What are Environmental Operations expenses?

A. Environmental Operations expenses consist of labor and materials supporting the operations of the Company's AQCS. As Federal and State emissions 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. Now that the Company has experienced multiple calendar years of operation, the Company anticipates these expenses to remain relatively consistent going forward. However, because the cost to operate and maintain these critical pieces of equipment is directly related to the operation of the coal-fired power plants they support, yearly variances in the total Environmental Operations expense should be expected based on the operation of the coal plants in a given year.

Q. Please explain how the projected 2020 bridge period and 2021 test year Environmental Operations expenses were calculated.

A. Environmental Operations expenses are a combination of O&M costs related to the environmental equipment at the Karn and Campbell sites. The operations component is 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.

2019 is the third full year of operations of the environmental equipment at both Campbell and Karn, and the Company now has robust historical data to use in projecting these expenses.

MAJOR MAINTENANCE

Q. What are Major Maintenance expenses?

A. Major Maintenance represents O&M projects that are not necessarily performed annually. Instead, the expenses are based on asset condition or on historic maintenance intervals over multiple years. To maintain and improve the performance of our generating fleet, the Company performs Major Maintenance on a regular basis. However, completion of Major Maintenance work can be influenced by, among other things, actual operations of the generating units, availability of parts and labor, and energy market conditions.

Q. Please explain how the projected 2019-2020 bridge period and 2021 test year Major Maintenance O&M expenses were determined.

A. Major Maintenance expenses are determined by tracking both the historical and future maintenance needs for each site and unit, considering operation safety, unit reliability, and maximum customer value. Individual projects are calculated in a manner similar to capital projects, as discussed earlier in this testimony.

Q. Please identify the 2021 test year Major Maintenance O&M expenses.

A. The Company projects that it will incur $34.756 million in Major Maintenance O&M expenses during the test year, as identified by Exhibit A-70 (SAH-5), page 1, line 4, column (e). Test year Major Maintenance expense by generating unit is presented on Exhibit A-70 (SAH-5), page 3, column (d).

Q. Why is Consumers Energy spending $34.756 million in Total Major Maintenance O&M expense during the 2021 test year?

A. The Company is spending the majority of its Total Major Maintenance expense during the test year to maintain reliability. Reliability related Major Maintenance O&M expenses, made predominantly during scheduled outages, allow the plants to avoid equipment issues that would lead to more frequent random outages, exposing customers to potentially more expensive replacement energy at market prices. Minimizing forced outages by maintaining equipment improves the likelihood the unit will be available when needed.

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

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

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

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

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

A. Yes. As the Company's generating units vary in age, size, type, and design, so do the costs to maintain these units. As an example, Major Maintenance of Campbell Unit 3 coal pulverizers (785 MW) would be considerably larger in scope and cost than Major Maintenance of Campbell Unit 1 coal pulverizers (260 MW), which is located on the same site.

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

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

Q. What are the categories of Major Maintenance?

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

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

A. Outage maintenance O&M expenses are those associated with major overhauls and require that the generating unit be removed from service for boiler and/or turbine inspections and maintenance. These outages are typically scheduled on a periodic basis and are required by law, insurance providers, and/or industry standards to ensure operational safety and reliability. One example of a major maintenance outage is the periodic disassembly and repair of turbine control and stop valves. The valves control the amount of steam going to the turbine and are needed to control the unit output.

During an emergency situation, for example during unit electrical trip, the valves must react very quickly to stop the steam going to the turbine to prevent it from overspeeding. Overspeeding the turbine can result in severe mechanical damage resulting in a very long duration outage to repair, further resulting in increased cost to customers for market priced electricity during the outage. Periodic maintenance of turbine valves is required for personnel and equipment safety. Maintaining the valves on a periodic basis ensures that the clearances and internal components operate as designed and can reliably stop the turbine quickly when needed to prevent turbine or generator damage.

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

A. Boiler inspections assess the fire (outside) and steam (inside) sides of boiler tubing for weaknesses that will ultimately result in water/steam leaks. After the boiler has been properly opened, ventilated, and cleaned, scaffolding is constructed inside the boiler to provide access to the boiler tubes. Inspections are completed using a number of different methods – visual, non-destructive, and destructive. Visual and non-destructive testing are the most common methods of inspection. Non-destructive testing incorporates the use of ultrasonic, x-ray, magnetic particle, or like technologies to measure pipe wall thickness. Boiler tubes that are in poor condition or exceed minimum wall thickness are repaired or replaced. After all repairs are complete, boiler tubes are pressure tested. Each boiler is inspected on a specific time schedule, with a one-, two-, or three-year maximum interval. Internal components with known problems are inspected more frequently. External inspections are performed daily by Generation Operations and annually by state inspectors.

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

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

Q. Please define non-outage maintenance.

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

Campbell Units 1 and 2 Major Maintenance

Q. Are there any unique circumstances associated with Campbell Units 1 and 2 Major Maintenance expenses for the projected test period ending December 31, 2021?

A. Yes. Every 7 to 10 years Consumers Energy performs a major unit overhaul and inspection on each coal plant. This is consistent with OEM recommended intervals for turbine major maintenance and is both an industry and corporate practice. Such inspections are a key part of the system health and condition assessment programs that are important to maintaining unit reliability.

During the major unit outages, main turbine components are disassembled and refurbished as necessary, major motor and breaker maintenance is completed, and boiler system and auxiliary system inspections are performed.

Capital projects are completed as appropriate, taking advantage of longer periodic outage windows. Completing this major outage in 2021 is expected to carry the unit through its remaining life without the need for another major turbine-generator overhaul. However, component outages, like those required for turbine valves, will still be required.

Q. Please describe Campbell Units 1 and 2 Major Maintenance expenses for the projected test period ending December 31, 2021.

A. As shown on Exhibit A-70 (SAH-5), page 3, line 2, column (e), Campbell Units 1 and 2 Major Maintenance expense is forecasted to be $10.647 million in the projected test period ending December 31, 2021, and includes:

- Campbell Unit 1 Pulverizer Maintenance ($625,000). The scope of this project is the procurement of required parts to support the on-going maintenance of the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;

- Campbell Units 1 and 2 Periodic Outage Major Maintenance ($1,512,000). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during 2021. Expenses include planning, engineering services, materials, and overtime labor;

- Campbell Units 1 and 2 Stack Platform and Breeching Repair ($458,200). The scope of this project is to power brush and apply a rust inhibitive coating to the platforms, replace any severely rusted grating sections, perform necessary repairs to the concrete around the duct breeching, and make miscellaneous repairs as needed. The stack has four full circumference platforms and one rest platform that are degraded and in need of repair. In addition, the concrete liner is spalling around the duct breeching and this represents a safety hazard due to falling concrete debris;

- Campbell Unit 2 Turbine Inspection and Major Overhaul ($2,3700,000). The scope of this project is the major overhaul of the HP/IP/LP turbines. This work will include inspection and repair/rebuild of the turbines, including valves, bearings, controls and auxiliary systems, nozzle plates and blocks, rotors and blading, testing, and replacement of worn equipment, resulting in improved safety, reliability, efficiency, and performance of the unit;

- Campbell Unit 2 Generator Major Overhaul ($3,630,000). The scope of this project is the generator overhaul – stator rewedge and collector ring replacement. This overhaul will include inspection and repair/rebuild of rotor and stator, including bearings, hydrogen coolers, oil systems, insulation, and replacement of worn equipment, resulting in improved safety, reliability, efficiency, and performance of the unit;

- Campbell Unit 2 Mill Maintenance — Parts Only Boiler Plant Equipment ($310,000). The scope of this project is the procurement of required parts to support the on-going maintenance on the coal mill/pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;

- Fourteen additional Campbell Units 1 and 2 Major Maintenance projects totaling $1,275,000, with each individual project representing $225,000 or less in expenses. Projects include breaker, transformer, motor, and pump maintenance, induced draft fan modifications, installation of sudden pressure relay trip protection circuitry, screenhouse and tunnel cleaning, boiler safety testing, and coal bunker cleaning, inspection, and repairs; and

- Eight Site Common Major Maintenance projects totaling $1.087 million which are shared with Campbell Unit 3. Campbell Units 1 and 2 receive a 43% allocation totaling $0.467 million and Campbell Unit 3 receives a 57% allocation or $0.619 million. These projects, all of which represent less than $0.225 million in expense, include Dry Ash Landfill engineering support, fuel handling complex chute liner repairs, deepwater intake screen inspection, groundwater and corrective action monitoring, and fuel handling dumper outage repairs.

<u>Campbell Unit 3 Major Maintenance</u>

Q. Please describe Campbell Unit 3 Major Maintenance expenses for the projected test period ending December 31, 2021.

A. As shown on Exhibit A-70 (SAH-5), page 3, line 3, column (e), Campbell Unit 3 Major Maintenance expense is forecasted to be $4.636 million in 2021 and includes:

- Campbell Unit 3 Turbine Valve Inspections ($1,200,000). The scope of this project is the inspection and overhaul of the turbine valves. Turbine valves, if not maintained per industry standards, and Electric Power Research Institute and OEM recommendations, will develop blue-blush on stems and suffer other mechanical and hydraulic problems. The valves are critical components which protect the turbine from significant damage during turbine overspeed events;

- Campbell Unit 3 Outage Base-Boiler and Critical Maintenance ($715,000). The scope of this project is the periodic inspection and repair of boiler and major equipment during planned and scheduled periodic outages. This funding is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, remove fly ash deposits that impact both efficiency and reliability, and complete repairs that are identified during shutdowns and condition assessments. The performance of this work will result in safe, reliable, and efficient unit operation;

- Campbell Unit 3 Pulverizer Maintenance — Parts Only Mills-Boiler Plant Equipment ($417,999). The scope of this project is the procurement of required parts to support the on-going maintenance on the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;

- Campbell Unit 3 Spray Dry Absorber ("SDA") Maintenance ($373,240). The scope of this project is SDA maintenance targeted at addressing emergent issues, increasing reliability, and achieving regulatory compliance. Specifically, this maintenance will allow for critical inspections resulting in immediate minor repairs while providing data for future planned repair/replacement work. Overall, this work will be leading to increased reliability, reduced down time for repairs, increased/restored efficiency, and improved regulatory compliance for emissions control;

- Campbell Unit 3 BFP 3A and 3B Turbine Inspection and Overhaul ($187,000). The scope of this project is the inspection of the BFP turbines during the spring 2021 outage. The BFP turbines were last inspected in 2006 and are due for inspection in 2021. Due to minimal discovery in the previous inspections which were performed on a shorter inspection interval, the BFP turbines are on a 15-year inspection interval. The BFP turbine inspection will identify the potential scope of overhaul work to be performed in 2022. The BFP turbine inspection and subsequent overhaul will minimize the potential for turbine failure and turbine steam path collateral damage. The performance of the inspection and overhaul will increase both the operability and reliability of the turbine and its valves, significantly reducing the likelihood of forced outages resulting from BFP turbine equipment failure;

- Campbell Unit 3 Periodic Outage Major Maintenance ($279,930). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during 2021. Expenses include planning, engineering services, materials, and overtime labor. Performance of this work will result in improved unit reliability and performance;

- Nine additional projects for Campbell Unit 3 totaling $843,000 in expenses, with each individual project representing $209,000 or less in expenses. These projects include coal pipe elbow replacement, boiler testing and inspections, breaker maintenance, relay testing, high energy piping surveillance, SDA inspections, and burner tuning; and

- Eight Site Commons projects that I discussed previously with the Campbell Unit 3 allocation totaling $619,333.

Karn Units 1 and 2 Major Maintenance

Q. Please describe Karn Units 1 and 2 Major Maintenance expenses for the projected test period ending December 31, 2021.

A. As shown on Exhibit A-70 (SAH-5), page 3, line 4, column (e), Karn Units 1 and 2 Major Maintenance expense is forecasted to be $3.784 million in the projected test period ending December 31, 2021. This forecasted expense includes:

- Karn Unit 1 Mill Maintenance Materials, including coal pipe replacement - Boiler Plant Equipment ($370,000). The scope of work is the procurement of required parts, OEM support and contractor support (as necessary) for the on-going maintenance on the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;

- Karn Unit 1 Turbine Valve Inspections ($450,000). The scope of work is the removal, disassembly, inspection and repair of the governor valves, throttle valves, intercept valves, and reheat stop valves. Performance of this work will increase unit reliability as failure of these valves would require a forced outage for repair;

- Karn Unit 2 Mill Maintenance Materials, including coal pipe replacement - Boiler Plant Equipment ($470,000). The scope of work is the procurement of required parts, OEM support, and contractor support (as necessary) for the on-going maintenance on the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;

- Karn Unit 1 Forced Outage Repairs – boiler required maintenance ($200,000). The scope of this project is to repair boiler leaks during forced outages. Based upon history and ROR projections, Karn Unit 1 will experience three or more forced outages during 2021 which will require boiler repairs. In addition, ash will be vacuumed from the SCR and flue ducts once during 2021;

- Karn Unit 2 Forced Outage Repairs – boiler required maintenance ($200,000). The scope of this project is to repair boiler leaks during forced outages. Based upon history and ROR projections, Karn Unit 2 will experience three or more forced outages during 2021 which will require boiler repairs. In addition, ash will be vacuumed from the SCR and flue ducts once during 2021;

- Karn Units 1 and 2 Periodic Outage Major Maintenance ($700,000). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during 2021. Expenses include planning, engineering services, materials, and overtime labor.

- Karn Units 1 and 2 Boiler Required Inspections and Maintenance ($210,000). The scope of this work includes all required inspections and combustion tuning for MATS compliance and Boiler Certificate Inspections. This work will also support the Flow Accelerated Corrosion (“FAC”) inspection program required by the boiler safety program necessary to ensure personnel safety and to maintain a 3-year operating certificate. The inspections will inform remaining life estimates to high risk line segments that have been characterized as being susceptible to FAC. This project will maintain compliance with applicable laws and codes for boiler equipment;

- Thirteen additional projects totaling $1,046,000, with each individual project representing $200,000 or less, including high energy piping surveillance (“HEPS”), SDA maintenance, large particle ash screen replacement, breaker inspections and repairs, Part 115 groundwater monitoring, and dumper outage repairs and vegetation management; and

- Two Karn Site Commons projects totaling $275,000 for control systems cyber maintenance software Support and Karn groundwater treatment system O&M. The allocation for Karn Units 1 and 2 is $137,500.

Karn Units 3 and 4 Major Maintenance

Q. Please describe Karn Units 3 and 4 Major Maintenance expenses for the projected test period ending December 31, 2021.

A. As shown on Exhibit A-70 (SAH-5), page 3, line 5, column (e), Karn Units 3 and 4 Major Maintenance expense is forecasted to be $968,000 in the projected test period ending December 31, 2021, and includes:

- Karn Unit 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 2021. Expenses include planning, engineering services, materials, and overtime labor;
- Karn Units 3 and 4 Opacity Critical Equipment Repairs ($150,000). The scope of this major maintenance work is to perform critical maintenance and repairs on the plant equipment related to opacity issues. Karn Units 3 and 4 experience opacity excursions during operation on oil and gas. Performance of this work will maintain environmental compliance for the units;
- Five additional projects totaling $380,000 in expenses, with each individual project representing $120,000 or less in expense. These include boiler required repairs, breaker maintenance, major motor maintenance, and piping and isometric drawing updates; and
- Two Karn Site Commons projects totaling $275,000 for control systems cyber maintenance software support and Karn groundwater extraction system maintenance and optimization. The allocation for Karn Units 1 and 2 is $137,500 and the allocation for Karn Units 3 and 4 is $137,500 as well.

Zeeland Major Maintenance

Q. Please describe Zeeland Major Maintenance expenses for the projected test period ending December 31, 2021.

A. As shown on Exhibit A-70 (SAH-5), page 3, line 7, column (e), Zeeland Major Maintenance expense is forecasted to be $4.110 million in the projected test period ending December 31, 2021, and includes:

- Zeeland LTSA — Running Maintenance Contract ($1,750,000). Consumers Energy has a long-term maintenance agreement with GE to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;

- Zeeland Capacity Factor Used for Water and Chemicals ($900,000). 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 ($600,000). 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 $860,000 in expenses, with each individual project representing $255,000 or less in expenses. These include HEPS, FAC inspection, large oil-filled transformer maintenance, drum level control valve overhaul, and NERC-required relay testing.

<u>Jackson Major Maintenance</u>

Q. Please describe Jackson Major Maintenance expenses for the projected test period ending December 31, 2021.

A. As shown on Exhibit A-70 (SAH-5), page 3, line 8, column (d), Jackson Major Maintenance expense is forecasted to be $3,045,000 in the projected test period ending December 31, 2021. This forecasted expense consists of:

- Jackson 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 Capacity Factor Used for Water and Chemicals ($1,750,000). 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. Although the projected expense amount is based upon historical monthly invoice values at the time of the Company's 9&3 forecast, this projected amount is at risk due to recent actions by the City of Jackson with regard to monthly invoice amounts. Although the Company continues to manage the amount of water it consumes for plant generation, actual future expense may increase by as much as 200% over historical invoice amounts;

- Jackson LTSA — Running Maintenance Contract ($250,000). Consumers Energy has a long-term maintenance agreement with GE 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 LM6000 Generator Major ($200,000). Continue with current major inspection scope, fund high priority discovery work through emergent change log process. Pre-plan to execute similar work scope as was discovered during first generator inspection. Performance of this work will increase unit reliability, thereby reducing the likelihood of unplanned outages and emergent maintenance work; and

- Five additional projects totaling $445,000 with each individual project representing $175,000 or less in expenses. These include FAC, high voltage maintenance, HEPS, and compliance-based relay testing.

Ludington Major Maintenance

Q. Please describe Ludington Major Maintenance expenses for the projected test period ending December 31, 2021.

A. As shown on Exhibit A-70 (SAH-5), page 3, line 10, column (e), Ludington Major Maintenance expense is forecasted to be $2.828 million in the projected test period ending December 31, 2021, including:

- Fish Barrier Net - Installation, cleaning, and repairs and removal ($1,750,000). This is a FERC regulatory requirement. The net is installed annually and maintained to meet FERC license requirements and minimizes the impact of the Ludington Plant on fish in Lake Michigan;

- Reservoir remediation ($400,000). This is FERC required and related to dam safety, to ensure the Company maintains the integrity of the Ludington pond;

- Erosion Gullies Repair ($300,000). The scope of this project includes: additional engineering for modifications to Barr's design, and implementation of Barr's repair design for the two 5-foot-deep erosion gullies. The new repair design will include filling the deepest part of the 5-foot hole, rounding the remaining portion into a rounded swale, placing a geotextile to protect the filler and rounded out portion of the clay liner, and prevent further erosion of the clay liner. A small stone subgrade and rip rap will be placed on top of the geotextile to dissipate energy from runoff. This will eliminate the 5-foot-deep hole in the clay liner, restore the barrier to its original thickness, be more robust for erosion control, and will enable continual monitoring. The subgrade will prevent erosion and prevent the geotextile from getting damaged by the rip rap. This project will need to occur during the same year as the mastic liner replacement because the erosion gullies need to be repaired prior to installing the new mastic liner in the sections where erosion gullies is present;

- Ludington Unit 2 Generator Circuit Breaker ("GCB") life cycle ($175,000). The scope of this project is to perform maintenance on the Ludington Unit 2 GCBs (Generating and Motoring); and

- Four additional projects totaling $203,447, with each individual project representing less than $75,000 in expenses. These include PCB removal and disposal, asphalt liner inspection, Ludington Unit 6 intake scour repairs, and standby transformer maintenance and testing.

<u>Hydro Major Maintenance</u>

Q. Please describe Hydro Major Maintenance expenses for the projected test period ending December 31, 2021.

A. As shown on Exhibit A-70 (SAH-5), page 3, line 10, column (e), Hydro Major Maintenance expense is forecasted to be $4.546 million in the projected test period ending December 31, 2021, and includes:

- License Initiatives (General Hydro — $1,800,000). 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;

- Powerhouse structure assessment ($325,000). The scope of this project is to inspect and assess the condition of our dam powerhouse structures and structural integrity of these facilities. The newest structure is more than 80 years old and the oldest structures approaching 115 years of age. While these inspections are not currently required under a published FERC rule, FERC has shown increasing interest in this type of issue. The assessments will consist of an engineering review of site drawings and plans, a physical walk-through of all 13 sites to identify any discrepancies from the engineering review and/or other issues, and a consultation with the Operations team to discuss any known or previously identified concerns or issues. Once the evaluation is completed, a report will be provided to identify and prioritize issues as appropriate;

- Annual FERC Dam Safety Requirements including Part 12 Inspections (General Hydro — $800,000). 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. This same level of expense is budgeted annually from 2021 through 2024;

- Hydro Head Gate Hoist Assessments ($250,000). The scope of this project is to perform assessments on all head gate hoists which have not yet been evaluated to determine if the hoist is adequate based upon current standards. The scope of this assessment includes a review of the hoist ergonomics with respect to utilizing the chain chocks;

- Hodenpyl Downstream Wall Repair ($200,000). The soil on the slope downstream of the right segmental block wall (downstream wall) is moving downstream. This has caused the downstream wall to tip slightly in the downstream direction. The slope downstream of the segmental block wall also supports the northwest portion of the substation. If the movement of material continues, it could compromise the soil the substation is built on. The project scope will include an options study and engineering to determine the best solution for preventing the soil downstream of the wall from eroding away in 2020. In 2021, the design plans will be submitted to FERC for review. The engineering and drawings may be modified based on FERC's response. In 2022, the repair will be constructed;

- Hydro Concrete Repairs ($225,000). The scope of this project is to make necessary repairs to deteriorating concrete at all 13 river hydro facilities. This budgeted amount will allow for the performance of necessary repairs which are identified after spring flows or general deterioration. The identification of large concrete repairs will be considered in the annual budgeting process; and

- Twelve additional projects totaling $0.946 million, with each individual project representing $150,000 or less in expenses. These projects include updating inundation maps, cleaning relief well piezometers, apron, spillway, wall, chute, and headgate inspections and repairs, headgate, concrete repairs, and condition/risk assessments.

<u>**Admin and Other Major Maintenance**</u>

Q. Please describe Admin and Other Major Maintenance expenses for the projected test period ending December 31, 2021

A. As shown on Exhibit A-70 (SAH-5), page 3, line 11, column (e), the Company is not projecting Admin and Other Major Maintenance expense for 2021.

Classic 7 Major Maintenance

Q. Please describe Classic 7 (B.C. Cobb, Weadock, and J.R. Whiting units) Major Maintenance expenses for the projected test period ending December 31, 2021.

A. As shown on Exhibit A-70 (SAH-5), page 3, line 6, column (e), Classic 7 Major Maintenance expense is forecasted to be $0.193 million in the projected test period ending December 31, 2021.

Q. Why is Consumers Energy projecting to spend $0.193 million in Major Maintenance on the Classic 7 units in the projected test period ending December 31, 2021?

A. Although the Classic 7 units were retired in 2016, environmental regulations require the continued maintenance of the on-site ash ponds, which includes landfill license and inspections, groundwater and corrective action monitoring, vegetation management, and de-watering facilities.

KARN RETENTION AND SEPARATION PLAN O&M SPENDING

Q. Please describe the Karn retention and separation plan?

A. The Karn retention and separation plan is a people strategy that the Company has implemented to ensure that it can 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 and dark time period following retirement. The Company filed an IRP in June 2018, and one of the major elements of the Company's IRP was the retirement of two of its coal-fired generating units, Karn Units 1 and 2. On June 7, 2019, the MPSC approved the Company's IRP settlement agreement, including the retirement of Karn Units 1 and 2 in May 2023. The Company's IRP included detailed support of the Company's need to implement a retention and separation plan to ensure that it could operate the plants safely and reliably through their retirement date.

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

A. The Company has a strong interest in keeping qualified employees working at Karn Units 1 and 2 through their retirement date to ensure safe and reliable operations. The retention component will allow the Company to retain employees that may seek employment at other Company locations or outside of the Company. The Company's ability to hire new employees at Karn Units 1 and 2 will become increasingly difficult given the short remaining lifespan of the units and, to the extent that the Company has the ability to hire new employees, the training time necessary for any new hires will provide a significant challenge to operating the units both safely and reliably. The retention component utilizes the best practices that the Company employed in retiring the Classic 7.

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

A. When Karn Units 1 and 2 are retired, the Company plans to follow the terms of the collective bargaining agreement for Operating Maintenance and Construction ("OM&C") employees represented by the Utility Workers Union of America ("UWUA"), and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers will vary based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement within the Company within 60 miles from their current location, they will be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position as well as relocation expenses if they accept a position more than 60 miles away from their current location.

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

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

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

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

Employees receive a signing incentive equal to 15% of their base pay if they signed a retention agreement in October 2019. By signing the retention agreement, the employee agreed to forfeit their transfer rights under the current working agreement (for union employees) or under Company policy (for exempt and non-exempt employees). The employee must stay at Karn until October 31, 2020 to receive the payment; if the employee stays until that date, the incentive will be paid out to the employee within 30 days. If the employee separates from the Company before October 31, 2020, the employee forfeits the signing incentive.

Employees receive an annual incentive which graduates from 20% to 30% of their base pay for service each November in years 2019, 2020, and 2021, for staying at Karn and rendering service for the next twelve months. The employee must stay at Karn until October 31 of the following year to receive the payment; if the employee stays until that date, the incentive will be paid out to the employee within 30 days. If the employee separates from the Company before October 31 of the next year, the employee forfeits the annual incentive. Eligible employees will receive their first annual incentive payment in November 2020, a second payment in November 2021, and a third payment in November 2022.

Employees receive a final retention incentive equal to 60% of their base pay on or about July 1, 2023, if the employee is still at Karn. The payment is intended to incentivize employees to stay until the plant goes cold and dark and compensate employees for the service they rendered for the eight months (November 2022 through June 2023) prior to the payment.

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

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

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

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

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

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

Q. What are the projected costs for the Company's retention and separation plan?

A. As reflected on Exhibit A-70 (SAH-5), page 1, line 5, the Company is projecting total expense of $5.92 million in 2019, $12.97 million in 2020, and $7.41 million in 2021. The projected 2019 expense of $5.92 million is based upon expense of $3.46 million for retention and $2.46 for severance. The projected 2020 expense of $12.97 million is based upon expense of $12.81 million for retention and $0.16 million for severance. The projected 2021 expense of $7.41 million is based upon expense of $7.25 million for retention and $0.17 million for severance.

Q. Is the Company requesting specific accounting treatment of the projected expense associated with the Company's retention and separation plan?

A. Yes. Company witness Harry supports deferred accounting treatment for the Company's projected expense in both 2020 and 2021.

<u>CAMPBELL UNITS 1 AND 2 — AVOIDABLE MAJOR MAINTENANCE EXPENSE</u>

Q. Please describe Exhibit A-71 (SAH-6).

A. Exhibit A-71 (SAH-6) illustrates the Company's unavoidable and avoidable Major Maintenance expenses in the projected test year ending December 31, 2021, at Campbell Units 1 and 2 under different scenarios in which those units are retired in 2024 and 2025. The Company considered major maintenance expenses for the following six scenarios in Exhibit A-69 (SAH-4):

- retirement of Campbell Unit 1 in 2024;
- retirement of Campbell Unit 2 in 2024;
- retirement of both Campbell Units 1 and 2 in 2024;
- retirement of Campbell Unit 1 in 2025;
- retirement of Campbell Unit 2 in 2025; and
- retirement of both Campbell Units 1 and 2 in 2025.

Q. Why has the Company included avoidable Major Maintenance expenses for Campbell Units 1 and 2 in this proceeding?

A. As I discussed earlier, the Settlement Agreement approved by the MPSC in its June 7, 2019 Order in the Company's IRP, Case No. U-20165, required the Company to identify avoidable major maintenance for Campbell Units 1 and 2 in 2024 and 2025 retirement scenarios. The Company has not performed additional modeling to either support or reject the six retirement scenarios and relies solely on its currently approved IRP for decision-making purposes.

Q. What is the purpose of providing these avoidable Major Maintenance expense?

A. The purpose of Exhibit A-71 (SAH-6) is to illustrate the Major Maintenance expenses that the Company could avoid in the projected test year ending December 31, 2021, under each of the six retirement scenarios for Campbell Units 1 and 2 in 2024 and 2025. This exhibit, and its capital expenditure companion Exhibit A-69 (SAH-4), simply illustrate, in hindsight, the revenue requirement impacts of an alternative outcome in the Company's Commission-approved IRP.

Q. What are avoidable Major Maintenance expenses?

A. Avoidable Major Maintenance expenses represent Campbell Units 1 and 2 Major Maintenance expenses that are included in the projected test period ending December 31, 2021, that the Company could theoretically forego making in the event the Company made the decision to retire one or both of the Campbell units in 2024 or 2025. However, since the Company is operating in according with its Commission-approved IRP which reflects retirement of Campbell Units 1 and 2 in 2031, none of the Major Maintenance expenses identified in Exhibit A-71 (SAH-6) are practically avoidable.

Q. How did the Company determine which Major Maintenance expenses were avoidable?

A. For each of the six retirement scenarios for Campbells Unit 1 and 2 in 2024 and 2025, the Company performed a review of its projected Major Maintenance (both environmental and non-environmental) for the projected test year ending December 31, 2021 and made a determination as to whether the project would be required given the specific retirement scenario. Major Maintenance that was planned for the sole purpose of improving reliability and or efficiency were considered avoidable. Major Maintenance planned to maintain safety, environmental compliance, and/or continued operations were deemed unavoidable.

Q. Provide an example of an avoidable Major Maintenance expense.

A. An example of an avoidable Major Maintenance expense is the inspection and cleaning of medium voltage breakers for Campbell Units 1 and 2 in the projected test period ending December 31, 2021. This Major Maintenance is targeted to increase reliability of this equipment however it could be avoided in both a 2024 or 2025 Campbell Unit 1 or Campbell Unit 2 retirement scenario.

Q. Please explain the avoidable Major Maintenance expenses for the Campbell Unit 1 retirement scenarios for 2024 and 2025.

A. Exhibit A-71 (SAH-6), page 1, line 3, and page 2, line 3, show that under the 2024 and 2025 Campbell Unit 1 retirement scenario, \$0.129 million of non-environmental Major Maintenance could be avoided. The \$0.129 million of avoided non-environmental Major Maintenance for these retirement scenarios includes \$0.062 million for installation of a sudden pressure relay system on the generator step-up and station power transformers 1A and 1B and $0.067 million for breaker maintenance.

Q. Please explain the avoidable Major Maintenance expenses for the Campbell Unit 2 retirement scenarios for 2024 and 2025.

A. Exhibit A-71 (SAH-6), page 1, line 6, and page 2, line 6, show that under the 2024 and 2025 Campbell Unit 2 retirement scenario, $0.543 million of non-environmental Major Maintenance could be avoided. The $0.543 million of avoided non-environmental Major Maintenance for these retirement scenarios includes $0.175 million for transformer base maintenance, $0.100 million for motor maintenance, $0.100 million for pump maintenance, $0.075 million for coal bunker maintenance, and $0.083 million for breaker maintenance.

Q. Please explain the avoidable Major Maintenance expenses for the Campbell Units 1 and 2 retirement scenarios for 2024 and 2025.

A. Exhibit A-71 (SAH-6), page 1, lines 9 and 12, show that under the 2024 Campbell Units 1 and 2 retirement scenario, the avoidable Major Maintenance expenses for each unit are the same as those under the individual unit retirement scenarios for 2024. Similarly, Exhibit A-71 (SAH-6), page 2, lines 9 and 12, show that under the 2025 Campbell Units 1 and 2 retirement scenario, the avoidable Major Maintenance expenses for each unit are the same as those under the individual unit retirement scenarios for 2025.

Q. Why weren't all the Major Maintenance expenses for Campbell Unit 1 and Campbell Unit 2 for the six retirement scenarios determined to be avoidable?

A. Unavoidable Major Maintenance expenses represent Campbell Unit 1 and Campbell Unit 2 projected Major Maintenance expenses that are included in the projected test period ending December 31, 2021, that the Company must make even in the event the Company made a decision to retire one or both Campbell units earlier than 2031. Consistent with our generation asset strategy, the Company will continue to operate our generating units in a safe and environmentally compliant manner through their retirement date.

Q. Did the Company evaluate the ability to avoid any Major Maintenance applicable to Campbell Unit 3 in the above retirement scenarios?

A. Yes. The Company considered Major Maintenance expenses that are included in the projected test period ending December 31, 2021, that are common to the Campbell site. The Company's evaluation of these site common projects revealed that none of these projects, totaling $1.087 million, could be avoided in any of the six retirement scenarios. In addition, consistent with the Company's generation asset strategy for Campbell Unit 3 none of the major maintenance projects specific to Campbell Unit 3 could be avoided.

Q. What are Unavoidable expenses?

A. Unavoidable expenses represent Campbell Units 1 and 2 Major Maintenance expenses that are included in the projected test period ending December 31, 2021 that cannot be avoided even in the event the Company chooses to retire Campbell Units 1 or 2 in 2024 or 2025.

Q. Provide an example of an unavoidable Major Maintenance expense.

A. An example is the Campbell Unit 1 Pulverizer maintenance. As I previously discussed, this major maintenance work is absolutely necessary to maintain the operability of the coal pulverizers; thereby allowing the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions.

Q. Did the Company identify any incremental Major Maintenance expenses for any of the Campbell Units 1 and 2 retirement scenarios?

A. No. The Company did not identify Major Maintenance expenses for any of the Campbell units that would be pulled forward to the projected test period ending December 31, 2021.

Q. Would early retirement of Campbell Units 1 and 2 have an impact on base O&M?

A. No. Base O&M is unavoidable for the projected test year ending December 31, 2021, as operations and routine maintenance needs would be unchanged; base O&M does not decrease until the year of retirement because the units remain operational and reliable until that time. However, under any of the early retirement scenarios, the incremental O&M Major Maintenance impact of reduced capital investments has not been identified. If either or both of the Campbell units are retired early, it is possible that O&M Major Maintenance expense will increase, as equipment replacement that would otherwise be addressed via capital investments would instead be addressed via O&M. This will likely lead to decreased availability for the units as capital expenditures and O&M expense is reduced.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

KYLE P. JONES

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Kyle P. Jones, and my business address is 311 East Michigan Avenue, Battle Creek, Michigan 49014.

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 Fleet Services.

Q. What are your responsibilities as Director of Fleet Services?

A. I am responsible for all Fleet-based functions within Consumers Energy. This consists of Fleet Operations, Fleet Acquisition and Disposition, Licensing, Permitting, Regulatory (Federal, State, and Local), Technical Support and Training, and Strategy and Data Analytics.

Q. What is your formal educational experience?

A. I graduated from Kellogg Community College in 1993 with an associate degree in Applied Science - Industrial Engineering. In 1995, I also obtained an associate degree in Applied Science - Automotive Technology from Kellogg Community College. I have also completed numerous management courses, hold several leadership certifications, and I am also licensed as a certified Michigan Master Heavy Duty Technician with the State of Michigan.

Q. Would you please describe your previous work experience?

A. In 1992, I started my career as a Service Advisor for Battle Creek Ford. In 1994, I transitioned to working as a Diesel Mechanic at Wise International in Kalamazoo, Michigan. In 1997, I moved to Freightliner of Kalamazoo as a Service Manager.

In 2001, I started my career at Consumers Energy as a Fleet Field Leader for the Company's Pontiac location. In that position, I was responsible for all daily Fleet operations. In 2010, I was promoted to Senior Fleet Field Leader covering the west side of the state. In this role, I was responsible for the oversight of maintenance of more than 2000 Company-owned vehicles, equipment, and trailers. I was also responsible for providing supervision and support for 55 mechanics, 6 field leaders, and 6 administrative employees.

In 2011, I was promoted to the role of Fleet Regulatory and Technical Manager. In that role, I was responsible for ensuring that the Company's Fleet remained compliant with the Federal Motor Carrier Safety Regulations ("FMCSRs"), the Michigan Vehicle Code, American National Standards Institute ("ANSI") as well as Occupational Safety and Health Administration and Michigan Occupational Safety and Health Administration regulations. Additionally, my responsibilities included the creation of training programs to ensure that more than 100 Company mechanics were properly trained to perform the vast array of vehicle maintenance activities for the Company's Fleet.

In 2013, I accepted the position of Fleet Business Relations Manager. In this role, I was responsible for aligning Fleet strategic plans with Electric and Gas Operations. This included ensuring that vehicle specifications and equipment requirements of the Company's Fleet vehicles being built were consistent with the operational and work methods of employees carrying out Company functions and customer service in the field. My responsibilities also included the analyses of vehicle performance and budgetary impacts to the Fleet. In 2018, I was promoted to Fleet Acquisition and Business Relations Manager. This role consisted of aligning operations requirements for all Fleet capital purchases along with Fleet vehicle design, licensing, rentals, asset sales, and data management. In 2019, I accepted my current position in Fleet Services. In my current role as Director of Fleet Services, I am responsible for the supervision and oversight of 156 employees, which consists of: 112 mechanics, 14 administrative support staff, and 30 supervisors, analysts, and administrative support staff. I am also responsible for managing and maintaining over 7,000 units in our Fleet across 36 garages.

Q. Are you a member of any professional societies or trade associations?

A. Yes. I am a board member of the Electric Utility Fleet Managers Council, and a member of The Midwest Energy Associates Fleet Utility conference.

Q. What has been your involvement in previous proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. I have provided direct testimony in the Company's 2019 Gas Rate Case (Case No. U-20650) and provided witness support in the Company's 2018 Electric Rate Case (Case No. U-20134) and the Company's 2018 Gas Rate Case (Case No. U-20322).

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

A. The purpose of my direct testimony is to support the Company's costs related to the Electric business portion of Fleet services. To that end I will:

- Describe the Fleet Services function and associated responsibilities;
- Describe Fleet Services' balanced three-pronged approach to delivering customer value;
- Describe and support the 2017 Utilimarc Vehicle Replacement Report and the recommendations ("Utilimarc Report");
- Support the reasonableness and prudence of the capital expenditures for Fleet Services for the historical test year ended December 31, 2018; the bridge period beginning December 31, 2019 and ending December 31, 2020; and the projected test year ending December 31, 2021;

- Support reasonableness and prudence for the capital expenditures for Work Force Expansion; and
- Support reasonableness and prudence of the capital expenditures for Telematics.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (KPJ-1)	Schedule B-5.7	Summary of Actual & Projected Electric and Common Capital Expenditures for the years 2018, 2019, 2020, and 12 months ending September 30, 2021; and
Exhibit A-72 (KPJ-2)		2017 Utilimarc Vehicle Replacement Report.

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

A. Yes.

Q. Please briefly describe the exhibits you are sponsoring.

A. I am sponsoring: (i) Exhibit A-12 (KPJ-1), Schedule B-5.7, which is a Summary of Actual and Projected Fleet Capital Expenditures for the years 2018, 2019, 2020, and projected test year ending December 31, 2021; and (ii) Exhibit A-72 (KPJ-2), which is a report prepared by Utilimarc. The Utilimarc Report presents the results of a study of the Company's existing Fleet and future Fleet needs, including findings and recommendations for investment necessary to achieve and maintain a Fleet replacement strategy for the Company at a lower overall cost to customers.

<u>**Fleet Services Function and Responsibilities**</u>

Q. Please explain the Electric Operations Support function.

A. Electric Operations Support consists of the following support organizations: Fleet Services, Facilities, Real Estate, and Administrative Operations. Electric Operations Support provides support by acquiring, constructing, and maintaining assets required to operate the functional areas of the business.

Q. Are you addressing all support organizations related to Electric Operations Support in your direct testimony and exhibits?

A. No. I will be addressing Fleet Services only. Facilities, Real Estate, and Administrative Operations will be addressed in the testimony of Company witness LaTina D. Saba.

Q. Please explain the responsibilities of Fleet Services.

A. Fleet Services carries out all functions related to the acquisition and maintenance of Company-owned vehicles. Fleet Services is responsible for ensuring the safe operation of all vehicles, trailers, heavy equipment, and accessories required to operate the functional areas of the business.

Q. Please explain the scope of Fleet Services' management responsibilities.

A. Fleet Services manages a Fleet of over 7,000 units through their first, second, and, in some cases, third lifecycle for use in daily operational work.

Q. Please explain what you mean by "lifecycle."

A. The lifecycle is the age at which a unit is prepared for replacement. The lifecycle is defined as a balance between depreciation, maintenance cost, and condition.

Q. What functions comprise the Fleet organization?

A. The Fleet organization consists of four groups which collaboratively work together to provide value to Electric Operations to service our customers. The four groups which make up Fleet Operations are Acquisition/Disposition, Fleet Maintenance, Fleet Regulatory & Technical, and Strategy & Data Analytics.

<u>Balanced Three-Pronged Approach to Delivering Customer Value</u>

Q. What is the purpose of Fleet Services as it relates to the Company's Electric business?

A. Specific to the Company's Electric business, Fleet Services' purpose is to ensure that the Electric Operations Department can deliver reliable and uninterrupted operations. This is accomplished by beginning each day with zero Fleet impacts to service our customers and meeting the Electric business goals such as: (i) Customer On Time Delivery goals; (ii) Estimated Time of Restoration goals; (iii) Customer Average Interruption Duration Index goals; (iv) System Average Interruption Duration Index goals; and (v) System Average Interruption Frequency Index goals.

Q. What is the overall approach used by Fleet Services in carrying out its responsibilities?

A. Fleet Services balances three components – a quality component, a cost component, and a delivery component.

Q. Please explain the quality component of the approach utilized by Fleet Services.

A. The quality component of the Company's approach ensures the acquisition of the highest quality trucks, trailers, and heavy equipment at the lowest cost possible. Quality is measured by determining whether there has a been delay or impact on Electric Operations' ability to begin each day to service customers efficiently and execute the planned work without barriers or obstacles.

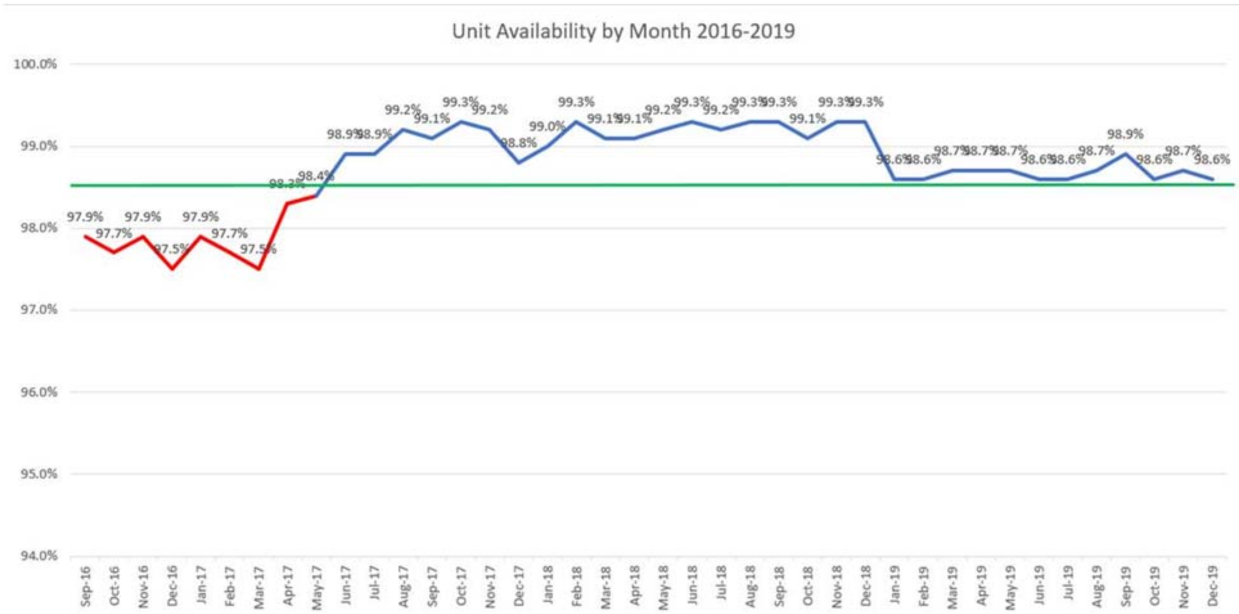
Q. Please explain the cost component of the approach utilized by Fleet Services.

A. Fleet Services places an emphasis on managing material cost, overtime, and outside services spend in order to provide Electric Operations a regulatory compliant, safe, and efficient Fleet to deliver on the Company's promises to customers. Additionally, Fleet partners with Electric Operations and vendors in order to effectively execute the Company's capital purchase plan.

Q. Please explain the delivery component of the approach utilized by Fleet Services.

A. For the delivery component, critical unit availability in real-time is measured across the state. Fleet began reporting Unit Availability in late 2016. See Chart 1 below that depicts unit availability from 2016 to 2019. The Unit availability, expressed as a percentage, has proven to be a critical metric to ensure that highest priority units are available for crews to complete their daily work. The Company's plan for 2019 and 2020 is to maintain a focus on unit availability. Unit availability is an output of total spend (cost) and predicts the level of impact on Electric Operations (quality). The goal is to balance the cost component against the level of unit availability to maximize efficiency and achieve zero start-of-day impacts to Electric Operations. By achieving zero Fleet-generated start-of-day impacts, Fleet Services provides value to Electric Operations by having the right unit at the right time to deliver on the commitment made to our customers. This is Fleet's commitment to maximize the value provided to Electric Operations and, ultimately, to external customers.

CHART 1 – Unit Availability Graph - Priority 1 & 2 Units



<u>**Utilimarc and the Utilimarc Report**</u>

Q. What is Utilimarc?

A. Utilimarc is an independent, third-party vendor and industry leader for utility Fleet analytics. Utilimarc began as a benchmarking company for companies with fleets, including Consumers Energy, and provided information to those companies to help them understand their fleet ranking amongst peers related to matters such as age of fleet assets, mix of fleet assets, lifecycle of assets, maintenance costs of assets, etc. Utilimarc now works as a strategic partner with companies such as Consumers Energy, to assist Fleet Utilities with maximizing their value within the company through the use of data analytics, statistical analysis, and real-world industry experience (see https://utilimarc.com/about-us/).

Q. What is the Company's experience with Utilimarc?

A. The Company has utilized Utilimarc for more than seven years for purposes of analyzing and benchmarking the Company's Fleet and Fleet performance against other utilities.

Q. Has the information provided by Utilimarc for benchmarking purposes been helpful?

A. Yes, the benchmarking information has been very useful but because it is a somewhat inexact science, the Company has determined that simply benchmarking the Company's Fleet performance against other utilities has not provided an accurate depiction of how Fleet impacts Electric operations. Thus, the Company requested Utilimarc to assist with analyzing Fleet's data to determine what drivers are necessary to make our Fleet more successful.

Q. How did the Company utilize Utilimarc?

A. The Company retained the services of Utilimarc to conduct a study of the Company's Fleet, utilizing the Company's data and Utilimarc's industry knowledge to provide the Company with recommendations regarding future plans for Fleet Services.

Q. Please explain Exhibit A-72 (KPJ-2).

A. Exhibit A-72 (KPJ-2) is the Utilimarc Report. This report was generated in 2017 when Fleet Services partnered with Utilimarc to determine what the appropriate lifecycle replacement plan should be for the Company's Fleet.

Q. Does the Utilimarc Report utilize Company data?

A. Yes. The Utilimarc Report, Exhibit A-72 (KPJ-2), utilizes the Company's data to determine the optimal lifecycle for the Fleet.

Q. Please generally summarize the learnings gained from the Utilimarc Report.

A. Consumers Energy learned that the Company's capital Fleet purchases were not optimally reducing Fleet spend, and that the Company has been reactively, rather than proactively, investing in Fleet. In continuing to do so, the Company also learned that it should expect an increase in Fleet costs. A discussion of Utilimarc's recommendations regarding the

Company's Fleet capital, and resulting Fleet expenditures, are discussed later in this testimony.

Q. Has the Company incorporated the recommendations set forth in the Utilimarc Report?

A. Yes, as demonstrated below, Exhibit A-12 (KPJ-1), Schedule B-5.7 incorporates the Utilimarc Report's proposed Fleet capital expenditures.

Fleet Services Capital Funding

Q. What has been the Company's historical approach to capital funding for Fleet Services?

A. In previous years, Fleet's capital funding was maintained at $17.5 million. This amount was utilized to replace out-of-lifecycle vehicles, heavy equipment, and trailers for all departments.

Q. How has the Company's previous investment strategy for capital funding affected the Company's Fleet?

A. The previous investments were not optimized for the age of the fleet and were not optimized for Fleet spend. As a result, the Company's Fleet has continued to age, creating increasing Fleet expenses needed to maintain a safe and useful Fleet for the Operations teams to serve customers.

Q. Why did the Company historically shift Fleet investments between Electric Operations and Gas Operations spend?

A. Historically, funding was inadequate to optimize the age of the entire fleet (for the Gas Operations and Electric Operations); therefore, emergent needs of the Company, based on increases in the Company's workforce, as well as the state of aging vehicles, determined where those funds were spent.

Q. What was the immediate and long-term result of this necessary shift between Fleet investment between Electric Operations and Gas Operation spend?

A. It created a constant cycle of "triage" for Fleet to service both sides of the business, which has negatively impacted the lifecycle of the entire Fleet. This impact, based on the previously-budgeted dollar amount, has resulted in a Fleet with an average age of over 8-years old and, in some cases 12- to 15-years old, and has also resulted in more than 1500 units out of 7000 being used beyond their lifecycles.

Q. Why is the advancing age of Fleet units problematic?

A. Units of this age experience much higher levels of maintenance problems. As a result, the constant "triage" of units for Fleet was necessary and persistent as aging units, experiencing maintenance problems at the end of any given day, had to be repaired throughout the night to make them operational and bring them back into service in time for them to serve customers the next morning.

Q. How did Utilimarc help with this problem?

A. The Company began utilizing Utilimarc' s analysis of the Company's data to identify the appropriate method to optimize the fleet and the maintenance costs.

Q. How did the Utilimarc data help to develop a forward-looking plan for Fleet Services?

A. In 2017, the Company's approach began to account for how data was utilized in order to deliver value to all of the operational groups that Fleet supports. Fleet partnered with Operations to determine which units were non-operational most frequently, causing missed critical dates and increased cost to customers. This information was then compared with the information of lifecycle data. Additionally, in 2017, the Company commissioned Utilimarc to conduct a study of the Company's historic Fleet ownership and operational data. This study was intended to help the Company develop a Fleet replacement plan by analyzing the Company's annual ownership and maintenance costs to determine the optimal time to replace units. Fleet Operations reviewed the Utilimarc Report (based on the Company's data), along with the Company's own observations, to develop a plan to replace out-of-lifecycle units in a manner that addresses the lowest cost and highest quality to allow us to best serve customers.

Q. Please describe the capital expenditures related to Fleet Services as shown on Exhibit A-12 (KPJ-1), Schedule B-5.7.

A. Exhibit A-12 (KPJ-1), Schedule B-5.7, includes Fleet Services Transportation Equipment and Other Equipment capital expenditure actuals for the 12 months ended December 31, 2018, projections for the 12 months ending December 31, 2019, projections for the 12 months ending December 31, 2020, the 24 months ending December 31, 2020, and projections for the 12 months ending December 31, 2021, which is the test year in this case. For the historical year, 12 months ended December 31, 2018, the Company incurred total Fleet Services capital expenditures in the amount of $17,967,000. The Company is projecting total Fleet Services capital expenditures to be $28,674,000 for the 12 months ending December 31, 2019; $33,222,000 for the 12 months ending December 31, 2020; and $61,896,000 for the 24 months ending December 31, 2020, as set forth in Exhibit A-12 (KPJ-1), Schedule B-5.7, line 8, column (b); line 8, column (c); line 8, columns (d) and (e); and line 8, column (f), respectively.

Q. Are there any contingency costs included in the Company's projected Electric Fleet Services capital expenditures?

A. No.

Q. What type of expenditures are included in Transportation Equipment?

A. Transportation Equipment includes the purchase of vehicles, heavy equipment, and trailers as part of the Company's Fleet Lifecycle Replacement Program that supports Operations.

Q. Please explain how the proposed spending levels for the bridge year and the projected test year ending December 31, 2021 were developed.

A. The proposed spending levels for the bridge year and test year are based upon the Fleet Electric Operations' capital investment plans. The bridge year ending December 31, 2019 projects capital expenditures of $28.674 million for transportation equipment (lifecycle replacement) and $243,000 for Fleet tool purchases. This total amount is reflected in Exhibit A-12 (KPJ-1), Schedule B-5.7, line 8, column (c). The bridge year ending December 31, 2020 projects capital expenditures of $33.222 million for transportation equipment (lifecycle replacement), $1.202 million for Telematics, and $240,000 in Fleet tool purchases. This total amount is reflected in Exhibit A-12 (KPJ-1), Schedule B-5.7, line 8, column (d). The 24-month bridge year ending December 31, 2020 projects capital expenditures of $61.896 million which consist of $60.211 million for transportation equipment (lifecycle replacement), $1.202 million for Telematics, and $483,000 for Fleet Tools. This total amount is reflected in Exhibit A-12 (KPJ-1), Schedule B-5.7, line 8, column (e). The projections for the test year ending December 31, 2021 projects capital expenditures of $62.749 million. This projection includes $32.005 million for transportation equipment (lifecycle replacement) as well as an additional request of

$24.494 million to support the additional Fleet units required for the workforce plan of Electric Operations adding Apprentices, Underground Construction workforce, and Journeyman. The test year also includes $6.009 million for Telematics and $240,000 for Fleet tools. This total amount is reflected in Exhibit A-12 (KPJ-1), Schedule B-5.7, line 8, column (f). The additional request for $24.494 million to support Electric Operations workforce plan and the Telematics project will be discussed below. This plan was developed using the analytics provided by Utilimarc for replacing out-of-lifecycle units. Consumers Energy is proposing test year spending consistent with the optimized analytical models produced by Utilimarc, utilizing the Company's data, in its recommendation.

Q. How did you determine the appropriate distribution of capital costs among the cost categories shown on Exhibit A-12 (KPJ-1), Schedule B-5.7?

A. As required by the Commission's filing requirements, the Company itemized the capital investments for Transportation Equipment by using the following cost categories: contractor, labor, materials, business expenses, and other. The Company does not specifically forecast its future capital spending needs by these cost categories. Although the Company has confidence in the total value, it was necessary to allocate the Company's total forecasted capital spending amount among the cost categories set forth in the filing requirements. The Company did so by calculating a five-year historical average of each of the Commission's prescribed cost categories from years 2014 to 2018 as a percentage of total Transportation Equipment investment over that same period of time. The five-year historical average for each cost category was then applied to the Transportation Equipment Program's projected capital spending for the bridge year and the test year to arrive at estimates for each cost category (i.e., contractor, labor, materials, business expenses, and other). This method is consistent for the projected test year presented in Exhibit A-12 (KPJ-1), Schedule B-5.7.

Q. Can the cost categories presented in Exhibit A-12 (KPJ-1), Schedule B-5.7, be applied to individual projects within the Transportation Equipment programs planned for the test year to determine how each project is broken down by cost category?

A. Yes. It should be noted, however, that the contractor, labor, materials, business expenses, and other costs presented in Exhibit A-12 (KPJ-1), Schedule B-5.7, are based on a five-year average of historical information as described above. While the historical information provides a reasonable estimate of the cost components of the projects planned for the test year, it is still an estimate.

Q. How does the Company's request differ from previous rates cases?

A. For the projected bridge year period ending December 31, 2020, Fleet Services is requesting a total capital expenditure amount of $33.222 million. This amount includes the Company's renewed request of $31.5 million to improve the lifecycle of the Electric Operations Fleet, $1.202 million for implementation of a new Telematics tracking system, and $240,000 for appropriate Fleet garage tooling and training. For the projected test year period ending December 31, 2021 Fleet Services is requesting a total capital expenditure amount of $62.749 million. This amount includes the Company's renewed annual request of $31.5 million for lifecycle replacement as well as an additional $24.494 million to support Electric Operations work force plan (which is a result of needed fleet units for additional workforce) and $6.009 million to complete the installation of the Telematics technology.

Q. Why is the Company renewing its request for incremental capital for Fleet lifecycle?

A. The Company's historical Fleet lifecycle for its highest cost, largest, and most critical units is, on average, 12 to 15 years before unit replacement. Based on the study performed by Utilimarc, and comparing the outcome of the study with our own internal data, the Company has determined that the optimal lifecycle for Electric Operations Fleet asset replacement is between five and eight years, on average, depending on unit type

Q. Please explain the breakdown of the Company's projected Fleet Services capital expenditures in this case for Electric Operations Transportation Equipment Fleet lifecycle.

A. Below is a breakdown of the projected Fleet Services capital expenditures purchase plan of $31.5 million for the projected test year ending December 31, 2020. This plan is based on the Company's analysis of out-of-lifecycle units. Nearly $26.902 million of this spend plan is allocated toward our most critical Electric Operations units. Additionally, the capital spend includes: contractor cost, business expenses, and other loadings/chargebacks incurred during the purchase of new units. The remaining $4.606 million in funding is allocated to the purchase of trailers and heavy equipment to support the work the crews are performing.

CHART 2 – Projected Fleet Services Capital Expenditures Purchase Plan

# of Units	Type of Unit	Total Acquisition Cost	
173	Crew Vehicles	$	26,902,000
28	Equipment	$	2,937,000
40	Trailers	$	1,669,550
241	**Grand Total**	**$**	**31,508,550**

Q. Why is $31.5 million of capital spending for lifecycle replacement required during the test year and what is the benefit to the customer?

A. Consistent spend levels will decrease the out-of-lifecycle units and improve the Company's overall lifecycle plan for the Fleet. As Exhibit A-72 (KPJ-2) indicates, a Fleet which is within the lifecycle model will ultimately require less maintenance which will provide value to our customers by reducing the overall Fleet Responsibility expense and having well-working vehicles to perform the work needed for our customers on time. Decreased overall Fleet spend will be dependent on consistently maintaining an optimal fleet age.

Q. How does the $31.5 million capital spend plan, year over year, benefit customers?

A. The Company's plan to establish a base Fleet purchase plan of $31.5 million for Electric Operations year over year benefits customers by incrementally moving to an appropriate Fleet lifecycle rather than the current approach which continues to increase Fleet expenses. As illustrated in Chart 3 below, there are currently $43.6 million worth of units outside of the eight-year lifecycle, and in need of replacement. However, to replace those units ($43.6 million) while implementing a more consistent program for unit replacement ($31.5 million) for out-of-lifecycle units would result in a total cost of $75 million to immediately improve the Company's entire Electric Operations Fleet to an eight-year lifecycle (or less) in the test year (2020-2021). The Company is not proposing such an approach, but is, instead, recommending a balanced approach which requires less capital and provides benefit to the customer by reducing Fleet expenses each year.

CHART 3 – Remaining Electric Fleet Units out of Lifecycle

# of Units	Type of Unit	Total Acquisition Cost	Cost per Unit
35	06's Sedan	$ 875,000	$ 25,000
15	23's Van	$ 825,000	$ 55,000
207	28/29's Support Pickup	$ 11,385,000	$ 55,000
1	46's Vacuum Truck	$ 600,000	$ 600,000
4	54's Single Axle Dump Truck 5 Yd	$ 480,000	$ 120,000
5	60's Light Duty Service Truck	$ 450,000	$ 90,000
5	64's Service Line Bucket	$ 850,000	$ 170,000
29	75/77's Digger Derrick	$ 7,250,000	$ 250,000
2	83's Stake Truck	$ 300,000	$ 150,000
1	85's Semi Tractor	$ 155,000	$ 155,000
37	89/96's Line Duty Bucket	$ 12,395,000	$ 335,000
1	90's Underground Crew Truck	$ 180,000	$ 180,000
5	99's Sub Metro Crew Truck	$ 750,000	$ 150,000
3	E10's Mobile Cart	$ 30,000	$ 10,000
2	E11/E15's Trencher	$ 240,000	$ 120,000
10	E20's Loader Backhoe	$ 1,150,000	$ 115,000
2	E26's Skid-steer	$ 216,000	$ 108,000
1	E43's Air Compressor	$ 25,000	$ 25,000
20	E60's Forklift	$ 840,000	$ 42,000
7	E80's Large Flex Track	$ 2,450,000	$ 350,000
10	E94's Tensioner/Puller	$ 810,000	$ 81,000
4	Off Road Tractor with Equipment	$ 240,000	$ 60,000
1	T59's Tankers	$ 150,000	$ 150,000
118	Trailers	$ 3,540,000	$ 30,000
525	Grand Total	$ 43,599,000	

Q. Were other factors considered in the Company's approach to capital investments for Fleet?

A. Yes. Spending large sums of capital for Fleet in a single year proves to be counterproductive for the Company and customers. One of many challenges of a large spending plan is the difficulty in executing the purchase plan due to vendor availability. Large orders for vehicles which are equipped with specialized equipment require time as vendors cannot turn around the size of such orders quickly. Another challenge in spending this sum of capital in a single year is the influx of units which all age together. With the influx of these vehicles aging at the same rate, they also experience maintenance issues at the same time. This causes clusters of unpredictable Fleet expenditures as the units age together and increases the likelihood of negatively impacting Electric Operations from servicing customers. This influx of vehicles would also create the need to make larger rate relief requests every eight years as those units age together and, in turn, have to be replaced together. This cycle of replacement results in an additional $75 million with compounding inflation, which would not be preferred.

Q. How have you arrived at a forecasted plan of $35.1 million to avoid this influx of units?

A. The Company utilized its own lifecycle analysis tools, and then compared the results with Utilimarc replacement analytics results and recommendations. By comparing capital needed versus operating cost, the Company has established that having a forecasted plan of $35.1 million annually will provide a consistent functional Fleet and enable the Company to predict and reduce volatility of Fleet expenses year after year.

Q. Please explain the breakdown of the Company's projected Fleet Services capital expenditures in this case for Other Equipment.

A. As explained in other sections of this direct testimony, the other equipment includes Fleet garage tooling and other vehicle maintenance equipment required to repair and maintain new and old makes and models of vehicles.

Q. Why is this tooling and other maintenance equipment necessary?

A. Automotive and Equipment technology is advancing at a staggering rate, which is requiring new and additional tooling, along with software, to make the necessary repairs and adjustments to the Company's vehicles and equipment in a cost effective and efficient manner.

Q. Can you explain the Company's expressed need for capital investment to support unit availability in light of the fact that unit availability is approaching 99%, as demonstrated in Chart 1 above?

A. The Company's ability to deliver unit availability at around 99% has only been obtainable through increased Fleet expense as the Company performs necessary maintenance and repairs (the "triage" discussed above) on out-of-lifecycle vehicles, often on a daily and nightly basis, to ensure their availability at the next start-of-day for Operations. This maintenance is not typical maintenance but is, rather, patchwork additional maintenance that would not necessarily be required for fleet units that are within their acceptable lifecycles. Further, this "triage" is accomplished by the Company's mechanics who work afternoon and overnight shifts, often in the form of overtime, to ensure vehicles are repaired. In the case of vehicles that are beyond repair for the next day's needs, those mechanics, in the alternative, arrange for the transport of another vehicle to the needed location to eliminate any impacts to Operations. These efforts to drive zero negative impacts to Operations with an aging Fleet necessarily creates increased cost for the Fleet Organization.

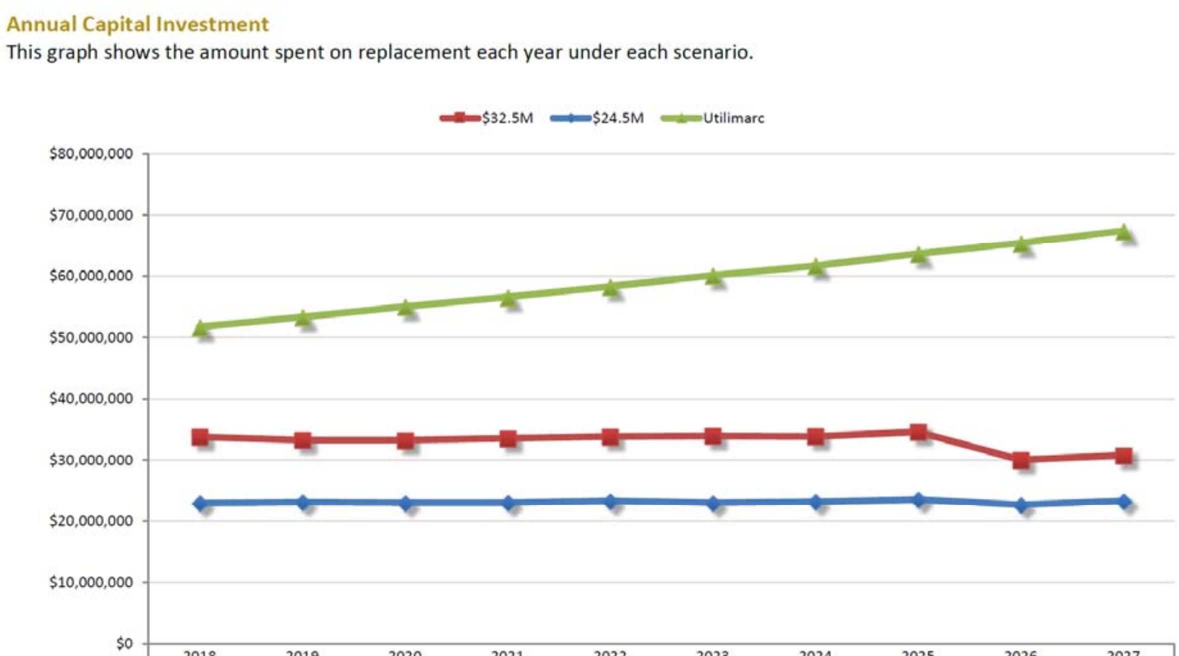
Q. Why were the capital expenditure amounts of $24.5 million and $32.5 million evaluated by Utilimarc in its report?

A. The $17.5 million in annual historical capital expenditures has resulted in increased and excessive maintenance cost, which has, in turn, created a Fleet which is aged and regularly places the Company in a position where its fleet has the potential to have negative impacts to Operations ability to serve our customers. When first approaching Utilimarc, the Company asked Utilimarc to create scenarios for different capital expenditure plans to better understand the impacts on the Fleet and the Company's ability to serve Operations. The first scenario the Company suggested was $24.5 million; this scenario continued to show increased maintenance costs and an aging Fleet. The second scenario, $32.5 million, was another scenario which was based on previous years historical reviews of the Fleet in an attempt to balance the investment plan with the maintenance spend. This scenario resulted in increased maintenance cost and an aging Fleet as well.

Q. Please summarize the annual capital investment recommended by Utilimarc for Fleet Services.

A. Chart 4 below illustrates the Annual Capital Investment to achieve an executable lifecycle plan for both Electric and Gas Operations using the following three capital spend plans: $32.5 million, $24.5 million, and the Utilimarc recommended spend. The Electric Operations portion of this spend is $31.5 million.

CHART 4 – Annual Capital Investment Scenarios



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
$32.5M	$33,843,200	$33,309,891	$33,271,622	$33,566,052	$33,880,842	$33,972,772	$33,885,658	$34,631,671	$30,062,981	$30,814,839
$24.5M	$23,000,500	$23,147,190	$23,019,403	$23,059,813	$23,333,475	$23,006,962	$23,195,665	$23,565,630	$22,725,850	$23,309,781
Utilimarc	$51,733,200	$53,331,546	$55,050,833	$56,579,424	$58,327,445	$60,155,568	$61,718,428	$63,653,027	$65,420,041	$67,441,404

Q. What is the basis for Utilimarc' s recommended increases year over year?

A. Based on market data, Utilimarc has added 3% for the expected inflation based on their analysis.

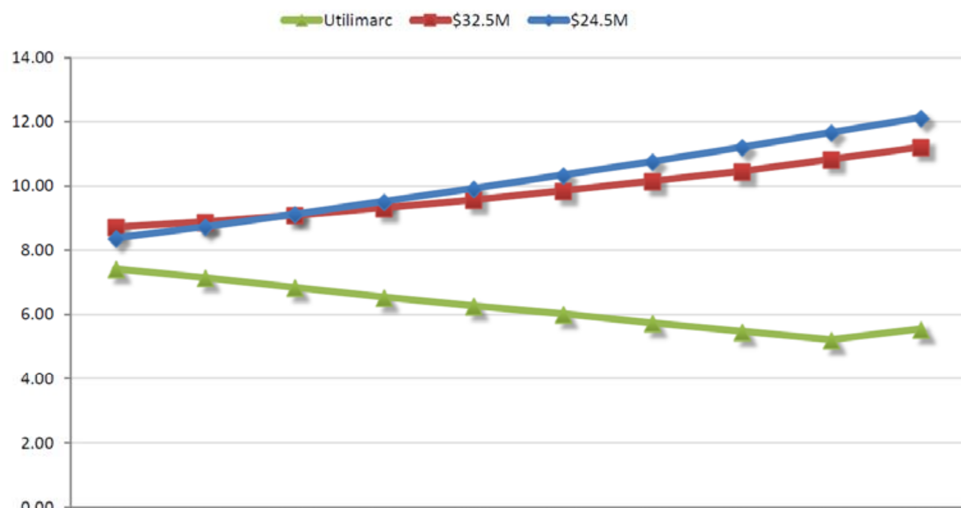
Q. Please explain how Utilimarc's recommended annual capital investment impacts the average age and maintenance cost of Fleet units.

A. Chart 5 below illustrates the impact of the age of the Company's Fleet when executing the recommended analysis performed by Utilimarc. By executing on the spending plan recommended by Utilimarc, the Company can reduce maintenance cost while simultaneously decreasing the average age of the Fleet by 4% per year. This results in an average Fleet age of 6.02 years in 2023, and, based upon the projections, the average Fleet age will further decrease to 5.55 years, which is the Company's targeted average age, in 2027. Additionally, by executing the Utilimarc plan consistently, the cost avoidance in 2027 is estimated to be $14 million less in maintenance while sustaining our past performance of zero impacts to start-of-day for Operations.

CHART 5 – Average Age of Units Scenarios

Unit Average Age

This graph shows average unit age of fleet over the next six years. Under the Utilimarc Budget scenario unit average age goes from 7.42 to 5.55 by 2027. Unit average age goes from 8.38 to 12.12 under the $24.5M Budget scenario and from 8.72 to 11.20 under the $32.5M Budget scenario.



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Utilimarc	7.42	7.15	6.85	6.54	6.27	6.02	5.74	5.47	5.22	5.55
$32.5M	8.72	8.89	9.09	9.31	9.57	9.85	10.15	10.45	10.83	11.20
$24.5M	8.38	8.73	9.12	9.52	9.92	10.34	10.76	11.21	11.67	12.12

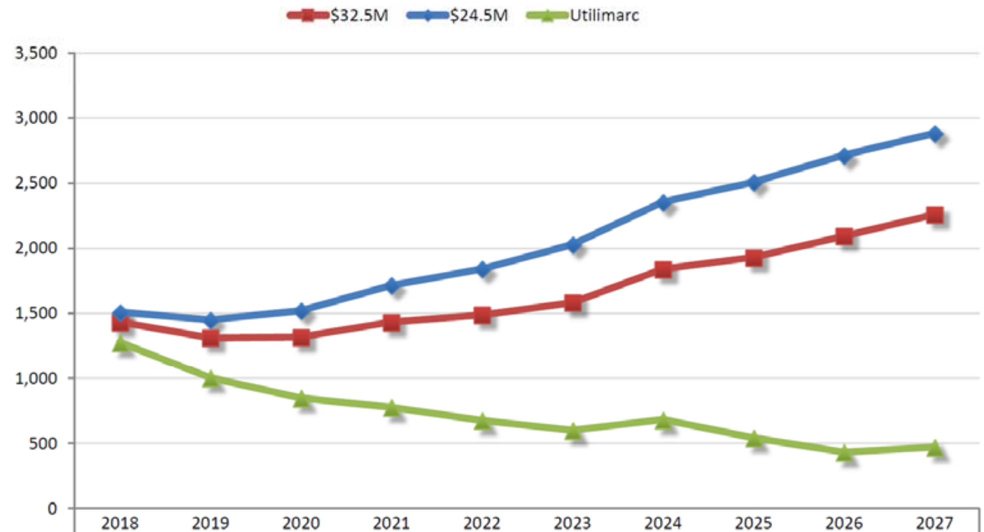
Q. What was the outcome of Utilimarc's analysis of spend plan, average age model, and lifecycle model?

A. Based on the Utilimarc analytics, utilizing Consumers Energy data, as demonstrated in Chart 6 below, if Consumers Energy invested only $24.5 million in its Fleet year over year, the total number of out-of-lifecycle units would grow by 1,373 by 2027. Conversely, investing $51.7 million in its fleet year over year results in a decrease in out-of-lifecycle units by 1,037 units by 2027. The lifecycle assumption in the chart for each year utilized the replacement age for each vehicle class which represents the lowest total annualized cost.

CHART 6 – Units Out of Lifecycle

Units Out of Lifecycle

This graph shows the number of units outside the stated lifecycle for each scenario. The target value for this metric is close to zero. In the Utilimarc scenario the number of units out of lifecycle decrease from 1,279 to 472 by 2027. The number of units out of lifecycle increases from 1,509 to 2,882 in 2027 in the $24.5M Budget scenario and increases from 1,433 to 2,259 in 2027 in the $32.5M Budget Scenario.



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
$32.5M	1,433	1,312	1,318	1,433	1,489	1,582	1,840	1,930	2,094	2,259
$24.5M	1,509	1,451	1,522	1,716	1,842	2,028	2,354	2,507	2,713	2,882
Utilimarc	1,279	1,003	849	777	676	601	682	543	432	472

Q. What did the Company learn from Utilimarc regarding the Company's Fleet spend plan, average age model, and lifecycle model?

A. The lifecycle, average age, and spend plan models proposed by the Company in this case, as well as previous rate cases, which is based on the analytical models from Utilimarc using Company data, ensures each Fleet asset is fully utilized and disposed of before elevated Fleet expenses are incurred in year seven to eight and beyond. This will optimize the Fleet spend as well as optimize the residual values recovered at disposal.

Q. What do you mean when you say that the Company will also be able to optimize the residual values recovered at disposal?

A. At the Company's current spend, Fleet units are often in excess of 12 years of age when they are disposed of by the Company. Units of this age bring lower sale values when the

Company ultimately retires the vehicles, recapturing less to reinvest in newer vehicles. Under the Utilimarc plan, the average age of Fleet units is expected to be 5.5 years. At that age, Fleet units will bring a much higher value when the Company retires and sells those vehicles, leaving much more to reinvest in new vehicles.

Q. What other concerns does the Company have if the proposed capital expenditures amounts are not approved?

A. Along with the immediate concern of reliability and availability to serve customers, if the proposed capital expenditures are not approved, and the Company is unable to invest capital in its Fleet as recommended, the Company is concerned that there will be significant missed opportunities of having the new technology offered by the Original Equipment Manufacturers. Technology is always advancing, particularly as it relates to safety, and new technology often provides assistance to Company employees who operate those vehicles – giving them the ability to prevent potential accidents. Reduction in safety incidents and accidents is not only positive for Company employees who operate those vehicles, it also reduces maintenance and repair necessary for avoidable accidents and reduces impacts to customers. Important safety features include, but are not limited to, lane departure warnings, blind spot monitoring, front crash sensors with braking technology, adaptive cruise control, and many other driver safety benefits listed in Chart 7 below. These safety features increase the average acquisition cost by $7,000 to $15,000 per unit which, without the additional funding, negatively impacts the Fleet lifecycle and, in turn, causes Fleet expenses to continue to rise, diminishing the value the Company delivers to Electric Operations to serve customers.

CHART 7 Safety Enhancements

Sedan Safety Enhancements		
Adaptive Cruise control		
Blind Spot Sensing		
Lane Departure		
360 Camera System		
Pre-Collision assist for Pedestrian	=	$14K
Adaptive Cruise control		
Front Crash Sensor		
Parking Assist		
All Wheel Drive		
Rain Sensing Wipers		

Pick-up Safety Enhancements		
Adaptive Cruise control		
Adaptive Steering		
360 Camera Sys		
Blindspot sensing	=	$7K
Front Crash Sensor		
Lane Departure		
Auto High Beam w/Rain Sensing		

Medium Duty Chassis Safety Enhancements		
Stability Control		
On Guard Collision		
Adaptive Cruise control	=	$15K
Lane Depature		
Disk Brakes		

Q. Please explain the Company's concerns regarding future Fleet expenses if the requested capital expenditures amounts are not approved.

A. As described within the study conducted by Utilimarc, the capital expenditures requested directly correspond to the expected Fleet expenses of the Company. The historical capital expenditure plans have created, and will continue to create, an increase in age of Fleet units, demand work orders, and maintenance expense. The total anticipated projected increase in demand orders over the 10-year period is 19% or a total of 92,000 orders. Additionally, the anticipated maintenance cost is projected to increase by 21% over the 10-year period which results in an overall increase of $82 million. The concern of not approving the capital plan is that maintenance cost will continue to rise, and the condition of the Fleet will continue to decline. The challenge with not having the appropriate capital expenditures creates difficulties in maintaining the Fleet in a condition to provide optimal performance without increasing maintenance cost. Based on the Company's data and the outcome of the Utilimarc study, using their industry knowledge, the Company must increase replacement spend to provide the appropriate level of service to Electric Operations and reduce cost for customers.

Q. Why is an increase in Fleet expenditures so important?

A. The Fleet has been reaching a tipping point in its ability to keep costs reasonable and properly serve customers. Necessary growth in the Company's Fleet, combined with units beyond their lifecycles, is causing Fleet expense to continue escalating.

As the Utilimarc analytics indicates, demand work orders, annual maintenance cost, average age, and lifecycles will continue to increase, resulting in higher Fleet expense due to the need for major repairs to an out-of-lifecycle Fleet. This higher Fleet expense will ultimately elevate expenses to our customers – in the form of dollars and in less reliable service. By increasing the capital spend plans, Fleet expense is more predictable because the need to perform catastrophic repairs on out-of-lifecycle units is reduced, allowing the Company to properly serve customers.

<u>**Electric Operations Workforce Expansion**</u>

Q. The Company's capital exhibits related to Fleet reflect expenditures for workforce expansion in Low Voltage Distribution ("LVD")/High Voltage Distribution ("HVD") Electric Operations. Please explain what this is.

A. Fleet is requesting $27.320 million to support Electric Operations LVD/HVD workforce expansion efforts. Specific details relating to the work plan of this expansion of Electric Operations is being addressed in Company witness Richard T. Blumenstock's direct testimony. Specific details relating to the additional headcount to support the work plan is being addressed in Company witness Douglas E. Detterman's direct testimony.

Q. How does this Capital Expenditure benefit the customer?

A. The capital expenditure benefits the customer by reducing the cost to maintain out-of-lifecycle units. As discussed in detail above, keeping units back in service past their useful life is cost prohibitive. Unpredictable maintenance escalates with units outside of their lifecycles which is represented in the Utilimarc Report, Exhibit A-72 (KPJ-2).

Q. What concerns does the Fleet have if the proposed capital expenditures amounts are not approved?

A. Fleet is concerned that out-of-lifecycle units will increase as the Company will be forced to do extraordinary maintenance to keep units in service to support Electric Operations efforts. This growth in aged units will create unpredictable maintenance costs. As established above in this direct testimony, if the proposed capital expenditures for Fleet are not approved, maintenance costs are estimated to increase an additional $14 million in year 2027 along with an increase in out-of-lifecycle units to the Fleet, which will only add to the increased maintenance expense. Additionally, Fleet would not have enough units to support the expansion efforts of Electric Operations which would negatively impact Electric Operations' ability to complete the work and deliver value to customers, as outlined in the direct testimony of Mr. Blumenstock and Mr. Detterman.

Q. Were other factors considered in the Company's approach to the vehicle and equipment needs to support this workforce expansion?

A. Yes. Two other factors were considered regarding the need to support the additional work plans and headcount. The first consideration was to place retired Fleet units back in service after being replaced. This has proven to be cost prohibitive due to the age and lifecycle of the units and the related unpredictable and exorbitant cost in keeping units in active service well beyond their lifecycles. This is the basis for the lifecycle replacement request of $31.5 million. The second consideration was to rent units from third-party vendors to support this need. Renting the needed quantity of units is not only unfeasible due to the quantity of units needed, but also the rental companies, as a general rule, do not have readily available units which meet the technical specifications Electric Operations requires to perform their work. For example, rental companies generally do not have tandem axle line bucket trucks, emergency road side lighting, the Company's radios, and the Company's docking stations for laptops. Additionally, renting units is more expensive due to the nature of the business. Rental companies charge a premium above the initial purchase price to rent the units. The premium cost would create a negative effect to our customers. Additionally, the quantity of units needed would require the rental companies to procure the vehicles and equipment which would require the same amount of time for Consumers Energy to procure the equipment resulting in no gain in time.

<u>**Telematics as an Element of Capital**</u>

Q. The Company's capital exhibits related to Fleet reflect expenditures for "Telematics." Is this new? Please explain what this is.

A. Yes, this is a new request. Telematics is a combination of hardware and software used for monitoring vehicles, equipment, and trailers by using Global Positioning System ("GPS"), the various control modules within the units, and the vehicles' onboard diagnostics.

Q. Does the Company's Fleet currently have a similar technology?

A. Currently the Company's Fleet has two separate GPS tracking systems. The first system is Track-star which is equipped on all operational vehicles and was purchased by the

Company in 2006. The second system is Fleetilla, which is utilized on rental units and specialty equipment.

Q. What does Track-star do and why is the Company replacing it?

A. Track-star technology only provides a means of locating vehicles and providing simple information to identify if the engine is running and if the Power Take-Off is in operation. This technology was implemented to better schedule Company vehicles and crews by providing visibility to their locations. Additionally, technological offerings from the manufacturers and vocational equipment, as well as the sunsetting of the 3G network, has rendered the Track-star platform ineffective technology. Further, Track-star is no longer supporting upgrades to the Company's platform, which has created the necessity for Fleet to pursue other offerings with more up-to-date and advanced technologies.

Q. What does Fleetilla do and why is the Company replacing it?

A. Fleetilla is purely a tracking devise for latitude and longitude for our rental and specialty equipment for the purpose of locating and performing maintenance. This technology does not provide any additional functionality.

Q. Why did the Company choose Utilimarc Telematics as a replacement for Track-star?

A. Most Telematics companies offer the same inputs and outputs of the data; however, after seeking guidance from peers of other utilities, Fleet determined that the main ingredient to the success of Telematics is the level of service and support the Telematics company provides. Many companies provided insights into and comments regarding high implementation failure rates, poor data quality, generic solutions which did not fit utility industry needs and poor support after installation. Utilimarc's comprehensive data analysis has provided many Fleet teams with the tools, reporting, and dashboards necessary to effectively manage Fleet operations. In addition to Fleet analytics, Utilimarc also has the resources to resolve any of the data- or analytic-related needs quickly and professionally. Two significant reasons for using Utilimarc are that they: (i) specialize in utility fleets; and (ii) can integrate and overlay the vehicle information within the various platforms of Electric Operations to combine multiple data points which will deliver value added services to our customers.

Q. What are the main differences between Utilimarc Telematics and Track-star?

A. Utilimarc Telematics is more robust, and its technology is more advanced than the current Track-star system. The chart below represents a comparison which demonstrates the vast amount of data inputs which can be retrieved from using this newer technology.

CHART 8 - Telematics Comparison

Functionality of Technology	*Utilimarc Telematics (NEW)*	*Trackstar(CURRENT)*
Intergration to SAP	Yes	No
Integration to Work Order Mgmt System	Yes	No
Intergration to Infrastructure- Gas Information Systems & Mapping	Yes	No
Intergation to HR Systems	Yes	No
Intergration to OEM Chassis	Yes	No
Intergration to Vocational Equipment	Yes	No
Integration to WEX & Smartfill fuel reporting	Yes	No
Off road diesel tax recovery for non-road use benefit	Yes	No
GPS Location Latitude and Longitude	Yes	Yes
Accurate vehicle locations	Yes	Yes
Driver safety reporting	Yes	No
Street level routing - improved response time	Yes	No
Geofencing -Start and end of day reporting	Yes	No
Electronic DVIR (FMCSR)	Yes	No
Unit optimization	Yes	No
Idle mitigation	Yes	No
Preventative maintenance improvements	Yes	No
Predictive maintenance - repair information is submitted electronically	Yes	No
Vocation Reporting - Boom out of Stow, Air Compressor Operation	Yes	No
Warranty Cost Recovery	Yes	No
Data Interpreting	Yes	No
Benchmarking Supplementation	Yes	No

Q. Does the acquisition and implementation of Utilimarc Telematics impact the capital spend in this case versus the Company's last electric rate case, Case No. U-20134?

A. In the 2018 Electric Rate Case application, Fleet Service requested a total capital expenditure of $31.7 million. This dollar amount was requested and approved so that the

Company could execute its lifecycle improvement plan and Fleet tooling purchases. In this filing, the Company has requested an increase of $7.211 million for the needed Telematics. Fleet services is continuing to ask for the same capital spend ($31.7 million), to execute our lifecycle improvement plan and tooling purchases. The additional capital dollars ($7.211 million) requested in this filing is to include the purchase and installation of Utilimarc Telematics for our Fleet units.

Q. What are the overall benefits of implementing the Utilimarc Telematics system?

A. There are multiple components that add value regarding Telematics: Safety, Automation, Data Management, Optimization, and Productivity.

Q. What are the safety benefits of implementing the Utilimarc Telematics system?

A. The safety items of the Telematics system track driver behaviors, such as speed, harsh braking, and cornering. Evaluations can be created for each vehicle, using this information, to educate drivers on their performance and the impacts of their driving styles. This is important because Consumers Energy drives approximately 46 million miles per year in the state of Michigan delivering value to our customers. According to information obtained from other companies using Utilimarc Telematics, the customized educational training developed using Utilimarc Telematics has demonstrated a reduction of driver safety events by approximately 36%. The data provided by the Telematics systems also supports accident investigations. Having the exact location of the vehicle prior to an accident, along with the critical information of vehicle speed and braking supports the investigation process. Another safety benefit is the ability to notify our operators of specific threats of violence. In 2018, there were 348 threats of violence to our operators. This technology has the ability to integrate geofencing with the threats of violence notifications to warn operators to help them avoid being placed in harm's way.

Q. What are the automation benefits of implementing Utilimarc Telematics?

A. The system offers an application for drivers to allow them to document the Driver Vehicle Inspection Report ("DVIR") which is required by the FMCSRs. The Utilimarc Telematics application has the functionality for electronic completion of the DVIR. The automation allows this process to be paperless, which eliminates the need to physically track and file forms, it also has valuable capabilities which notify Fleet personnel, and the ability to create work requests, when a defect in a vehicle requires maintenance. This technology enables a dashboard to be created showing DVIR completion, as well as vehicles in need of repairs, which notifies Operational planners for scheduling adjustments prior to start of day. It also allows for the opportunity to integrate the electronic driver's log, which allows dispatchers to view available hours prior to scheduling work.

Q. What Data Management benefits are realized by implementing the Utilimarc Telematics System?

A. The integration between the Company's SAP system and Utilimarc has already been established which benefits the customer. This allows Utilimarc to integrate Operator Qualifications with the vehicle for dispatch to precisely identify the right vehicle, with the qualified operator and tools to respond and serve our customers. Having this ability to dispatch the nearest qualified crew to serve our customers results in lower expenses as well as increasing our value delivered to the customers.

Q. What optimization benefits are realized by implementing the Utilimarc Telematics system?

A. The optimization portion of the application provides accurate tracking of miles and hours of the asset which gives insight to the utilization of each vehicle as well as ensuring any rental units are being fully utilized. The Telematics will also provide insights to our preventative maintenance programs. The programs will have the functionality to be tailored to the specific asset per the manufacturer's recommendations. This technology has the ability to integrate with our fuel card vendors, WEX and Smartfill, as well as the ability to track fuel usage and idle time. The fuel reporting is important because it provides us the ability to track off-road gallons used and accurately obtain credit for the road taxes paid as well as identify maintenance trends due to excessive fuel usage. The idle tracking along with fuel utilization provides an opportunity to reduce fuel consumed by educating our drivers to change their behaviors on how much fuel is used for non-productive idle time. The reduced idle time also helps us achieve our environmental goals of reducing carbon. This technology offers engine fault codes and remote diagnostics as well. Having this insight to identify predicative maintenance trends prior to catastrophic repairs or extended downtime allows Fleet the ability to plan the repairs versus having unplanned work. Avoiding unplanned work is important because it increases overtime and additional materials to make the necessary unexpected repairs to avoid impacting Electric Operations from starting their day with zero impacts to serve our customers.

Q. What productivity benefits are realized by implementing the Utilimarc Telematics system?

A. The productivity of the Telematics arises out of the ability to integrate and overlay onto many of our current systems. The integration allows us to view, on one central screen: (i) the location of crews; (ii) weather maps; (iii) street level routing; (iv) travel times for crews; (v) the qualifications of crew members; (vi) Electric infrastructure mapping and systems; (vii) work order assignments; (viii) amount of time at the jobsite; (ix) contractor locations; (x) bore crew locations; (xi) wire guards; (xii) MISS DIG requests and information; (xiii) No-Light calls, and much more. The ability to collect all of these data points in one place and on one screen will allow dispatchers the ability to analyze and provide a level of coordination of information that Fleet Services has never experienced. The output of this data will provide us with a lens to better understand how the Company can reduce non-premises time, eliminate waste in our day, and deliver world class performance to our customers.

Q. Can you quantify the economic benefits for customers by implementing Telematics?

A. A significant portion of the benefits in the chart below are based upon saving 20 minutes per day per crew member. A majority of the savings for Electric Operations will be achieved by dispatchers seeing the locations of the work, available crews, supporting crews (contractors), MISS DIG tickets, and incoming No-Light calls on one screen, versus the five different screens currently needed to obtain that information. Having the ability to overlay this information onto one screen diminishes the time and complexity of the decision-making process which will, in turn, allow for the optimization of crew resourcing, travel time and equipment placement. The productivity the Company anticipates gaining will avoid multiple trips and or truck rolls to our various job sites. The geofencing allows the leadership to track performance of crew arrival times to identify unnecessary stops as well as providing the visibility to the amount of time crews are at the job sites to monitor non-premises time. The investment required to implement this technology is $7.211 million; the savings and cost avoidance of implementing this technology (Telematics) is estimated annually at $4.476 million ($3.564 million Capital and $891,000 Operating and Maintenance) for Electric Operations which will equate to lowering the Company's overall expense for our customers. This project anticipates recapturing the investment and providing a positive return to our customers in less than two years.

CHART 9 - Telematics Savings

Description of Savings for Electric Operations				
Fuel Savings		***Capital***	***O&M***	***Total***
Fleet Fuel Savings - Idle Reduction- 10 Min Per Day- 5508 Veh/Equip		$ 133,596	$ 33,399	$ 166,995
Fleet Fuel Savings - 5% Miles Reduction		$ 257,475	$ 64,369	$ 321,844
Fleet Fuel Savings - Off Road Diesel Tax Recovery		$ 228,253	$ 57,063	$ 285,316
Total Fleet Fuel Cost Benefit		**$ 619,324**	**$ 154,831**	**$ 774,155**
Maintenance Savings		***Capital***	***O&M***	***Total***
Maintenance - Warranty Claims Recovery		$ 133,874	$ 33,468	$ 167,342
Maintenance - 50% Reduction in Jump Starts		$ 96,574	$ 24,143	$ 120,717
Maintenance - Predictive Maintenance - DTC Codes/Troubleshooting (time)/Materials		$ 214,225	$ 53,556	$ 288,059
Total Maintenance Cost Benefit		**$ 444,672**	**$ 111,168**	**$ 576,118**
Electric Operations (Daily Time Savings)		***Capital***	***O&M***	***Total***
Electric Lineworker Time Savings Per Day ***This is done through Geo-Fencing specific locations to reduce wasted time existing the service center, gas station stops, returning to the service center early or multiple times per day and providing the optimal routes for the drivers to take to the job sites .Having visability to circuits and contractors will enhance dispatcher decision making to reduce redundant truck rolls for crews performing work***	*20 Min Per Day, 550 Lineworkers @ $47 per hour*	$ 1,792,190	$ 448,048	$ 2,240,238
Electric Service Worker Time Savings Per Day ***This is done through Geo-Fencing specific locations to reduce wasted time existing the service center, gas station stops and returning to the service center early or multiple times per day. This technology provides the dispatchers real time critical information regarding no-light calls allowing the dispatchers to route the nearest most qualified worker to the request.***	20 Min Per Day, 98 Service workers @ $49 per hour	$ 336,336	$ 84,084	$ 420,420
Electric Meter Operations Worker Time Savings Per Day ***This is done through Geo-Fencing specific locations to reduce wasted time existing the service center, gas station stops and returning to the service center early or multiple times per day. This technology provides the dispatchers real time critical information regarding no-light calls allowing the dispatchers to route the nearest most qualified worker to the request.***	*20 Min Per Day, 41 Meter Worker @ $46 per hour*	$ 130,649	$ 32,662	$ 163,311
Electric Operations - Electronic DVIR Submission *** This will contribute 10 minutes to the 30 minutes described above for the 550 lineworkers***	Reduced Jump Starts, Headlights, Break Fix Overnight, Etc.	Embedded Above	Embedded Above	Embedded Above
Total Daily Time Savings Cost Benefit		**$ 2,259,175**	**$ 564,794**	**$ 2,823,969**
Rental Utilization		***Capital***	***O&M***	***Total***
Electric Rental Expense Reduction - $3,019,944 Annual Expense	10% of Annual Rental Cost Reduction	**$ 241,595**	**$ 60,399**	**$ 301,994**
Grand Total Projected Savings		***Capital***	***O&M***	***Total***
		$ 3,564,766	***$ 891,192***	***$ 4,476,235***

Q. Please describe the risk of utilizing the current GPS tracking system.

A. The current Track-star system was selected as a corporate high impact risk due to a "on classic support" system from our Track-star vendor. Currently Track-star Version 5 is being utilized by the Company which has been unsupported by Track-star for approximately two years. The unsupported, archaic technology only allows us to receive critical patches to maintain the solution but this version does not allow us to take advantage of software improvements required to satisfy key business requirements. Samples of the key business requirements have been included in the direct testimony and savings chart above.

Q. Are you addressing the entire Telematics project within this direct testimony?

A. No. This testimony is only addressing the Electric Operations portion of the Telematics project. The Company is planning on addressing the need for Telematics for Gas Operations within the Gas Rate Case testimony.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697

DIRECT TESTIMONY

OF

MICHAEL P. KELLY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

PUBLIC VERSION

February 2020

Q. Please state your name and business address.

A. My name is Michael P. Kelly, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director, Corporate Strategy.

<u>QUALIFICATIONS</u>

Q. Please describe your educational background.

A. In 2002, I received a Bachelor of Science in Engineering in Mechanical Engineering from the University of Michigan – Ann Arbor. In 2005, I received a Master of Science in Engineering in Mechanical Engineering from the University of Michigan – Dearborn. In 2009, I received a Master of Business Administration from the University of Michigan – Ann Arbor.

Q. Please describe your business experience.

A. From 2002 to 2007, I was employed by Yazaki North America in Canton, Michigan as an engineer working in roles that spanned Testing and Validation and Component Engineering. I left Yazaki North America in 2007 to pursue a Master of Business Administration, and upon receiving my degree in 2009, I accepted a position at DTE Energy Company ("DTE") as a Financial Consultant where I assumed roles in Financial Planning and Analysis, Distribution Operations Decision Support, and Renewable Energy Business Development. In 2012, I accepted a position working in DTE's Electric Strategy organization and was promoted to Manager of the team in 2014. As Manager of the Electric Strategy team, I was responsible for the development of the electric utility's annual priority plans and long-term financial planning functions. In 2017, I accepted the role of Manager within DTE's Tree Trimming organization. In this role, I was responsible for the long-term and annual maintenance trimming schedules and execution of contracts with the providers of tree trimming and herbicide services. In October 2018, I accepted a position as a Director, Corporate Strategy at Consumers Energy.

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

A. The purpose of my direct testimony is to request Michigan Public Service Commission ("MPSC" or the "Commission") approval of the Long-Term Industrial Load Rate ("LTILR"), also referred to as the Long-Term Industrial Load Retention Rate ("LTILRR"), and the electric rate contract ("HSC Contract") between the Company and Hemlock Semiconductor Operations LLC ("HSC") as provided by Public Act 348 of 2018, MCL 460.10gg ("Act 348"). Finally, I am sponsoring the projected HSC Contract revenues resulting from the negotiated rate for the projected test year.

Q. How is your testimony organized?

A. My direct testimony is organized as follows:

- Long-Term Industrial Load Rate – describes the LTILR and how the requirements in Act 348 have been met;
- HSC Contract – describes how the HSC Contract is consistent with Act 348; and
- HSC Contract Revenues for the Test Year – calculates the expected revenues attributed to the HSC Contract for the test year

Q. What is an LTILR?

A. Act 348 provides eligible large industrial customers with the ability to receive an electricity rate which is based on the cost of a designated power supply resource. The Company's proposed rate to provide this option is the LTILR.

Q. What criteria does Act 348 require for Commission approval of the LTILR?

A. The LTILR must satisfy a number of requirements, including:

- The rate is based on the cost of one or more designated power supply resources;
- The customer agrees to a long-term contract to pay the costs for the designated power supply resources for the expected remaining life of the resources;
- The customer's electricity usage has an average annual electric demand of at least 200 MW at a single site and an annual load factor of at least 75%; and
- The customer can demonstrate a self-service alternative to standard utility tariff service.

Q. Please provide a summary of the HSC Contract?

A. The HSC Contract is the agreement for the LTILR between the Company and HSC with a term from January 1, 2021 to May 30, 2041. The HSC Contract includes HSC's initial capacity elections in Part I and describes HSC's ability to update those capacity elections in Section 3.2. HSC Contract charges are based on a single designated power supply resource, the Company-owned Zeeland combined cycle generating ("Zeeland CCGT") as defined in Section 2.4, and the direct cost of providing HSC with transmission service, Section 4.2.5, and distribution service, Section 4.2.6. Under the HSC Contract, HSC pays a Capacity Charge of [redacted], as indicated in Section 4.2.2, that has been set at the levelized cost of capacity of the Zeeland CCGT over the term. The HSC Contract also outlines the methodology by which HSC will be charged for consumption of energy. [redacted]

[redacted]. To ensure HSC pays for the actual costs of energy provided to HSC under the LTILR, the contract includes an Annual Energy Charge True-Up reconciliation process, Section 4.6. The HSC Contract outlines additional terms and conditions ranging from the administration of the contract to termination rights which will be discussed later in my testimony.

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

A. Yes, I am sponsoring the following exhibits:

Confidential Exhibit A-73 (MPK-1):	Calculation of HSC Contract Revenues; and
Confidential Exhibit A-74 (MPK-2):	HSC Contract.

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

A. I prepared Confidential Exhibit A-73 (MPK-1): Calculation of the HSC Contract Revenues. Confidential Exhibit A-74 (MPK-2): HSC Contract was the result of an agreement between the Company and HSC for the Company to provide service to HSC under the LTILR.

Q. Does your testimony rely on information provided by any other Company witnesses?

A. Yes. Company witness Richard T. Blumenstock supports the loss factors which are used for the adjustments made to calculate HSC's Contract Capacity Charge and for the calculation of the HSC Contract Revenues in my Confidential Exhibit A-73 (MPK-1). Company witness Eugene M. Breuring supports HSC's forecast coincidence factor that was used to calculate the Contract Capacity Charge in the HSC Contract. Company witness Scott A. Hugo supports the calculation of the term of the contract as set forth by the remaining expected life of the designated resource, the net demonstrated generating capability and equivalent forced outage rate demand of the designated resource used to calculate the Contract Capacity Charge in the HSC Contract, and the designated resource's variable operations and maintenance expense used in calculating the HSC Contract Revenues for the test year as identified in my Confidential Exhibit A-73 (MPK-1). Company witness Hubert W. Miller supports the calculation of the net benefit provided by the HSC Contract. Company witness Heidi J. Myers supports the calculation of the levelized costs of the designated resource that are used to calculate the Contract Capacity Charge in the HSC Contract and the Distribution Charge used in calculating HSC's Contract Revenues as identified in Confidential Exhibit A-73 (MPK-1). Company witness Keith G. Troyer supports the heat rate, fuel, and aqueous ammonia costs for the designated resource, the cost of market purchases, the Midcontinent Independent System Operator, Inc. ("MISO") charges and credits, and the transmission costs used in calculating HSC Contract Revenues for the projected test year as identified in Confidential Exhibit A-73 (MPK-1). Finally, Company witness Rachel L. Barnes sponsors the LTILR tariff sheets in Exhibit A-16 (RLB-2), Schedule F-5.

LONG-TERM INDUSTRIAL LOAD RATE

Q. Is the Company proposing an LTILR for approval?

A. Yes. The LTILR is sponsored by Company witness Barnes as Exhibit A-16 (RLB-2), Schedule F-5.

Q. What are the eligibility requirements for the LTILR?

A. Consistent with Act 348, the LTILR is available to industrial full-service customers who have an average annual electric demand of at least 200 MW at a single site, have a minimum load factor of 75%, and have provided a sworn affidavit which demonstrates that they would not purchase standard tariff service from the Company except under the LTILR.

Q. Is a contract needed for the LTILR?

A. Yes. The eligible customer must enter into a contract for a term, equal to: (i) the term of the designated power purchase agreement or agreements, which in no case shall be for less than 15 years for one or more designated power supply resource if the resource is a power purchase agreement or agreements; or (ii) the expected remaining life of one or more designated utility-owned power supply resources.

Q. Based on the Company's proposed LTILR, what capacities does the customer contract for?

A. As depicted in the following chart, the customer contracts for the following capacities when taking service under the LTILR:

1. Maximum Contracted Capacity - The maximum amount of electric capacity eligible for purchase by the eligible customer under the LTILR for the term;
2. Annual Forecast Capacity - The amount of electric capacity the customer expects to use in the MISO Planning Year beginning June 1 and ending May 31 of the following calendar year;
3. Firm Contracted Capacity - The amount of electric capacity of at least 100,000 kW and not more than the Annual Forecast Capacity that the Company will supply to qualifying customers that is not subject to the Interruptible Service Provision;
4. Reserved Capacity - The difference between the Maximum Contracted Capacity and the Annual Forecast Capacity held in reserve for future customer growth during the term; and
5. Interruptible Service Capacity - The difference between the Annual Forecast Capacity and the Firm Contracted Capacity.

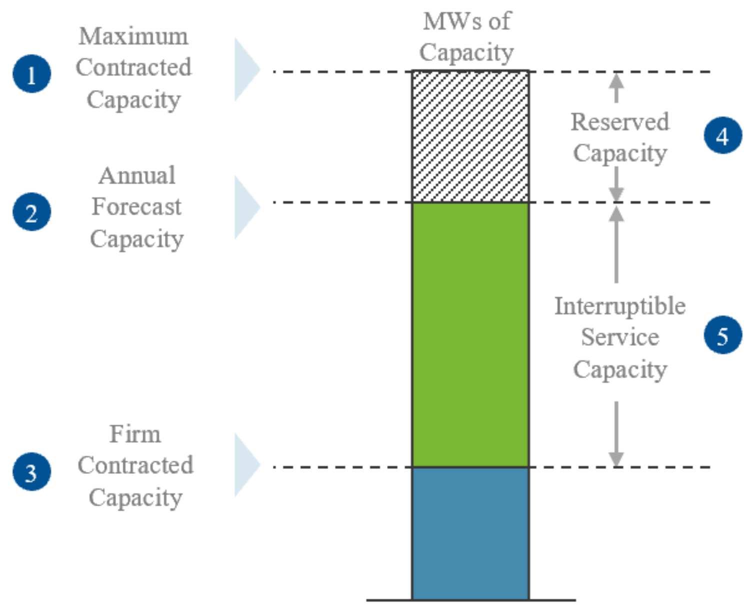


Chart 1: Illustration of Contracted Capacities in the LTILR

Q. What costs are the eligible customers responsible for under the LTILR?

A. The LTILR customer pays for the cost of administering the contract for the LTILR, the direct utility costs for providing transmission services, and the direct utility costs for providing distribution services. The customer also pays the cost of service for capacity based on one or more designated power supply resources, and the actual cost of production from the designated power supply resources, including fuel and variable operations and maintenance expenses, or the displacement cost of such expenses as it relates to their consumption. Additionally, the customer pays for capacity held in reserve for future customer growth during the term.

Q. What is included in the distribution costs?

A. The LTILR includes a Distribution Charge which is a fixed monthly charge to recover the cost of the Company's dedicated distribution facilities that are in place to serve the customer.

Q. What is included in the transmission costs?

A. The LTILR includes a Transmission Charge which is a monthly charge to recover the Company's cost to provide transmission service to serve the customer's load.

Q. What costs are included in the LTILR if the designated resource is a power purchase agreement?

A. If the designated resource is a power purchase agreement, then the LTILR is based on recovering all costs associated with the designated power purchase agreement.

Q. What costs are included in the LTILR if the designated resource is Company owned?

A. If the designated resource is Company owned, the LTILR is based on all of the following: (i) the Company's levelized cost of capacity, including fixed operation and maintenance expense, associated with the designated resource at the time the customer contract is executed; (ii) the Company's actual variable fuel and actual variable operation and maintenance expense based on the customer's actual energy consumption and associated with the designated resource; and (iii) the Company's actual energy and capacity market purchases based on the customer's actual consumption. The amount of capacity needed to serve the LTILR customer's load is based on the capacity needed by the Company to comply with MISO's resource adequacy requirement based on the amount of contractual firm and interruptible capacity supplied to the customer.

Q. How does the Company comply with MISO's load-serving resource requirements based on the customers' contracted firm and interruptible capacities?

A. The Company plans for the customer to consume the Firm Contracted Capacity during the Company's peak hour. This is accomplished by including the customer's forecasted peak coincident with the Company's coincident peak and the registration of the Interruptible Service Capacity as a Load Modifying Resource ("LMR") with MISO. As provided in the LTILR, the customer contractually agrees to reduce its total load level within 30 minutes of receiving an interruption notice from the Company, or as required by the MISO partial curtailment request, to a level that does not exceed the Firm Contracted Capacity.

Q. How are MISO's resource requirements used in determining the price the customer pays for capacity?

A. The LTILR includes a Capacity Charge on a $/kW-month basis that the customer will pay for the Annual Forecasted Capacity elected to be served through the LTILR. To arrive at the Capacity Charge, the levelized cost of the designated resource or resources is divided by the capacity of the designated resource including the requisite adjustments made to ensure MISO's resource requirements have been met.

Q. What adjustments are needed to account for MISO resource requirements?

A. Because the Annual Forecasted Capacity election is based upon the demand at the customer's meter, the LTILR rate accounts for the adjustments the Company makes to ensure MISO resource requirements are met for planning purposes. To arrive at a rate and capacity that includes these resource requirements, the net demonstrated generating capability ("NDC") of the designated resource is first adjusted by the designated resource's equivalent forced outage rate ("EFORd") to get to an equivalent Zonal Resource Credit ("ZRC"). The ZRC is then adjusted by the MISO Planning Reserve Margin Requirement ("PRMR") to come to an equivalent PRMR Capacity. This figure is then adjusted to account for line losses to develop a Loss Adjusted Capacity. Finally, the

Loss Adjusted Capacity is updated to account for the customer's coincidence with the MISO peak to ensure MISO resource requirements are accounted for in setting the LTILR Capacity Charge.

Formulas for determining capacity in setting the Capacity Charge are as follows:

1. ZRC = NDC * (1-EFORd)
2. PRMR Capacity = ZRC / (1-PRMR)
3. Loss Adj. Capacity = PRMR Capacity * (1–Customer Losses)
4. Resource Requirement Capacity = Loss Adj. Capacity / Customer Coincidence

Q. How are fuel, variable operations and maintenance, and market power expenses recovered through the LTILR?

A. The LTILR includes an Energy Charge which is based on the designated power supply resource's actual variable fuel and variable operations and maintenance expense, or the displacement costs of such expense, as applicable, associated with the customer's actual energy consumption. I will discuss displacement costs later in this testimony.

Q. What is the Interruptible Credit that is provided under the LTILR?

A. The credit under the Interruptible Service Provision is equivalent to the credit provided to customers receiving an Interruptible Credit under the Large General Service Primary Demand Rate GPD, Interruptible Service Provision (GI).

Q. What is the System Access Charge?

A. The System Access Charge is a monthly charge associated with the Company's administration of the contract through the term.

Q. What is the Reserved Capacity Charge?

A. The Reserved Capacity Charge is a $/kW-month fee that the customer pays for Reserved Capacity.

Q. What are the Excess Capacity Charge and the Excess Energy Charge and when would the customer be expected to pay these charges?

A. The Excess Capacity Charge is a $/kW-month fee charged when the customer's Maximum Monthly Demand exceeds the Maximum Contracted Capacity. The charge is based on the Power Supply Demand Charges (for Capacity and Non-Capacity) per the Large General Service Primary Demand Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level.

The Excess Energy Charge is a $/kWh charge for energy used in excess of the Maximum Contracted Capacity. The charge is based on the Power Supply Energy Charges per the Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level, including the applicable non-transmission Power Supply Cost Recovery Factor charges

Q. Should the Commission approve the proposed LTILR?

A. Yes. The Company requests that the Commission approve the LTILR as it meets the requirements set forth in Section 1 of Act 348.

<u>HSC CONTRACT</u>

Q. Is the Company proposing a contract for approval under the LTILR?

A. Yes. The Company is requesting approval of the contract with HSC for an LTILR. The Company and HSC entered into the HSC Contract for a LTILR on July 29, 2019.

Q. Did HSC meet the requirements for entering into a contract for an LTILR?

A. Yes. As supported by the direct testimony of Phillip M. Rausch, Business Development Director for HSC, HSC met all the requirements to enter into a contract for an LTILR as HSC had:

1. An annual average electric demand of at least 200 MW;
2. An annual load factor of at least 75%; and
3. Demonstrated that HSC would not purchase standard tariff service from the Company except under the LTILR.

Q. Does the HSC Contract require Commission approval to take effect?

A. Yes. Approval is needed and is defined in the HSC Contract in Section 2.3. In the event Commission approval is not obtained, the HSC Contract terminates on the earlier of January 1, 2021 or the date the Commission issues an order denying approval, in which case the Parties shall negotiate and in good faith attempt to enter into a new agreement within 180 days of termination of the HSC Contract.

Q. Has the HSC Contract been amended?

A. Yes, pursuant to an amendment dated January 31 2020. The HSC Contract including the amendment- has been provided as Confidential Exhibit A-74 (MPK-2).

Q. What changes were included in the amendment to the HSC Contract?

A. The Company and HSC amended the HSC Contract to:

1. Reduce the Initial Annual Forecast Capacity for HSC's updated load forecast;
2. Correct line losses to include Transmission system losses which were inadvertently excluded; and
3. Update the Capacity Charge and the Reserved Capacity Charge to reflect the updated line loss factor.

Q. When is the Company proposing that the HSC Contract take effect?

A. The Company is proposing that the contracted rates take effect on January 1, 2021, concurrent with the effective date of all rates in this case as defined in Section 8.1 of the HSC Contract.

Q. What is the term of the HSC Contract?

A. The HSC Contract has an initial term concluding at the end of the 2040/2041 MISO Planning Year on May 31, 2041 as defined in Section 8.1 of the HSC Contract.

Q. Can the HSC Contract be extended beyond the initial term?

A. Yes. The HSC Contract will extend on a MISO Planning Year by Planning Year basis until terminated by mutual consent or by either HSC or the Company providing six months' written notice.

Q. Can the HSC Contract be terminated prior to the end of the initial term?

A. Yes. The contract can be terminated early by the Company or HSC as provided in Section 8.2 of the HSC Contract. Before exercising any of the termination rights outlined in Section 8.2, the parties must attempt to negotiate a cure or settlement or reform the HSC Contract under Section 8.3.

Q. What costs will HSC pay under the HSC Contract?

A. The proposed HSC Contract is based on the levelized cost of capacity of the Zeeland CCGT at the time the contract was executed, the Company's actual variable fuel and actual variable operation and maintenance expenses based on HSC's actual energy consumption at the Zeeland CCGT, and the Company's actual energy and capacity market purchases, if any, based on HSC's actual consumption. Additionally, the LTILR includes the direct cost for providing HSC with transmission and distribution services as well an allocation of the charges and credits the Company receives from MISO. Finally, HSC pays for the cost of administering the contract for the LTILR.

Q. Is there a minimum charge that HSC must pay over the term?

A. Yes. Section 4.4 of the HSC Contract states that HSC will pay a Monthly Minimum Charge of the lower of the total amount due on the monthly invoice or the sum of: (i) the System Access Charge; (ii) the Distribution Charge; (iii) the Monthly Capacity Charge; (iv) the Monthly Reserved Capacity Charge; (v) the Monthly Interruptible Credit; and (vi) any non-consumption based Surcharges.

Q. What is the amount of the Firm Contracted Capacity?

A. The HSC Contract has a Firm Contracted Capacity of 100 MW for the term.

Q. What happens if HSC does not need 100 MW of capacity?

A. HSC cannot elect an Annual Forecasted Capacity less than the Firm Contracted Capacity of 100 MW. At a minimum, HSC will pay a Monthly Capacity Charge based on an election of 100 MW of Annual Forecasted Capacity. The Company will provide HSC a credit for the market value of the capacity contracted but not utilized. For example, if HSC only needs 90 MW of capacity in a Planning Year, the Monthly Capacity Charge will be based on 100 MW Annual Forecasted Capacity, and HSC will receive a credit for the market value of 10 MW.

Q. What is the maximum contracted capacity?

A. The HSC Contract has a Maximum Contracted Capacity of 400 MW for the term.

Q. On what power supply resource is the contracted capacity based?

A. As defined in Section 2.4 of the HSC Contract, the cost of service for the contracted capacity is based on a single designated power supply resource, the Company-owned Zeeland CCGT.

Q. Why was the Zeeland CCGT selected as the designated power supply resource?

A. Of the available resources in the Company's portfolio, the Zeeland CCGT most similarly represented the generating plant that HSC was planning to construct and had an expected remaining life that provided long-term price certainty.

Q. What is the expected remaining life of the Zeeland CCGT?

A. As supported by Company witness Hugo, the Zeeland CCGT is expected to operate through the 2040/41 MISO Planning Year.

Q. Is the term of the contract equal to the expected remaining life of the Zeeland CCGT?

A. Yes. Both the term of the HSC Contract and the expected life of the Zeeland CCGT are aligned with the expected conclusion of the MISO 2040/41 Planning Year on May 31, 2041.

Q. What is the levelized cost of capacity of the Zeeland CCGT?

A. Company witness Myers calculated the levelized cost of capacity, including fixed operation and maintenance expenses, for the Zeeland CCGT to be [redacted] as depicted in in Exhibit A-86 (HJM-67), Line 13.

Q. How were MISO's resource requirements used in setting the Capacity Rate in the HSC Contract?

A. The levelized cost of the Zeeland CCGT is adjusted to account for the MISO planning reserve requirement targets applicable to load-serving entities as follows:

- The Net Demonstrated Generation Capability of the Zeeland CCGT of 533 MW is first adjusted to account for the resource's capacity available to meet the MISO planning reserve target. Discounting the NDC by the Zeeland CCGT's EFORd of 0.68% yields 529 ZRCs that the Zeeland CCGT provides for planning purposes. Both NDC and EFORd information was provided by Company witness Hugo.
    - ZRC = NDC * (1-EFORd)
    - 529 MW = 533 MW * (1 – 0.68%)
- The next adjustment is made to satisfy the MISO capacity planning reserve margin target of 7.9% for the 2019 Planning Year at the time of contract execution. This planning reserve margin was taken from the MISO Loss of Load Study.[1] By dividing the equivalent ZRCs by (1 + the PRMR), the capacity at the Zeeland CCGT has been adjusted to account for the planning reserve margin requirements.
    - PRMR Capacity = ZRC / (1-PRMR)
    - [redacted]
- The next adjustment is made to account for [redacted] as provided by Company witness Blumenstock. By multiplying the equivalent PRMR capacity by (1 + HSC Losses), the capacity has been adjusted to account for the losses from generation to HSC.
    - Loss Adj. Capacity = PRMR Capacity * (1–Customer Losses)
    - [redacted]
- The final adjustment is made because HSC's peak demand occurs at a period different than MISO's peak demand. The capacity requirements are reduced based on HSC's demand coincident to MISO's peak demand. [redacted] adjustment was provided to me by Witness Breuring.

[1] September 11, 2018 MISO LOLEWG Meeting: https://cdn.misoenergy.org/20180911%20LOLEWG%20Item%2002%202019-20%20PY%20LRR%20%20PRM273420.pdf

- Resource Requirement Capacity = Loss Adj. Capacity / Customer Coincidence

[redacted]

The equivalent capacity of [redacted] at the Zeeland CCGT is needed to meet HSC's consumption in compliance with MISO's load-serving resource requirements.

Q. How is this equivalent capacity used in setting the Capacity Charge?

A. The levelized revenue requirement for the Zeeland CCGT of [redacted] is divided by the equivalent capacity of [redacted] to arrive at a levelized capacity cost of [redacted]. This value is divided by 12 months to determine the HSC Contract Capacity Charge of [redacted].

Q. Are the Company's actual variable fuel and actual variable operation and maintenance expenses recovered under the HSC Contract?

A. Yes. HSC pays for the Company's actual variable fuel and actual variable operation and maintenance expense ("Cost of Production") based upon its actual consumption as associated with the production from the Zeeland CCGT.

Q. Are HSC losses included in energy consumption?

A. Yes. HSC's consumption includes an adjustment to account for its energy losses of 2.36%. This adjustment ensures the energy needs are aligned to meet HSC's consumption. As illustrated in Chart 2, if HSC has a metered load of approximately 195.4 MW, that figure would be grossed-up by 2.36% to account for losses of nearly 4.6 MW to total HSC's consumption of 200.0 MW.

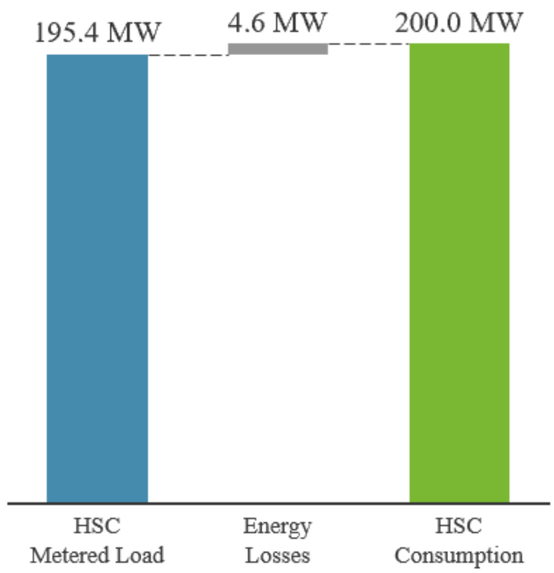


Chart 2: Illustrative Example of Calculating HSC Consumption

Q. How is the actual variable fuel component of the Cost of Production determined?

A. The actual fuel component of the Cost of Production is the product of the average monthly heat rate at the Zeeland CCGT and the monthly average cost of gas delivered to the Zeeland CCGT.

Q. Describe the actual variable operations and maintenance expenses.

A. The actual variable operations and maintenance expenses are the non-fuel, non-routine operational and major maintenance expenses that occur on an infrequent, or irregular basis. The magnitude and timing of the variable costs are often directly correlated to the Zeeland CCGT's utilization.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Q. Is the amount of capacity needed to serve HSC based on the capacity needed by the Company to comply with MISO's load-serving resource requirement, considering the amount of contractual firm and interruptible capacity supplied to HSC?

A. Yes. As illustrated in Chart 5, HSC is contracted to elect (1) Annual Forecast Capacity and (2) Firm Contract Capacity, which results in the (3) Interruptible Service Capacity. The Company plans for HSC to consume the Firm Contract Capacity during the Company's peak hour. This is accomplished by including HSC's forecasted peak coincident with the Company's coincident peak and the registration of an interruptible LMR with MISO. As provided in the HSC Contract, HSC agrees to reduce its total load level within 30 minutes of receiving an interruption notice from the Company, or as required by the MISO partial curtailment request, in an amount that does not reduce demand below the Firm Contracted Capacity.

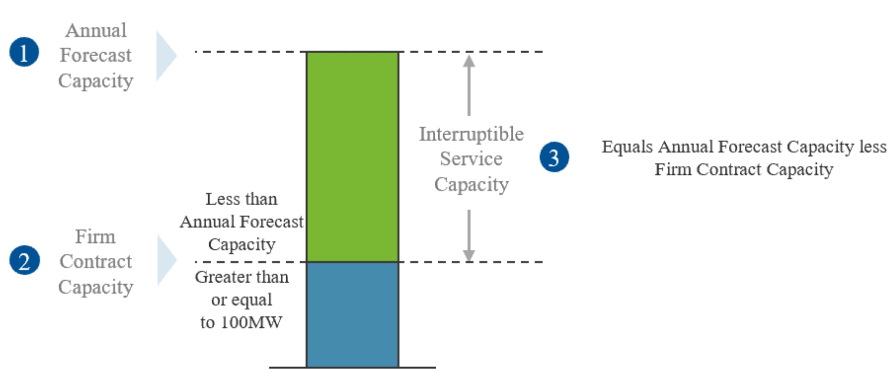


Chart 5: Calculation of Interruptible Service Capacity

Q. Does the contract include a true-up mechanism?

A. Yes. The contract includes an Annual Energy Charge True-up that will be used to ensure that the annual revenues collected through the HSC Contract captured the actual costs incurred by the Company for variable fuel, variable operations and maintenance expenses, and energy purchases. On an annual basis, the Company will conduct a reconciliation between the expenses charged to HSC and the expenses incurred by the Company. Any variance will be charged or credited to HSC over the 12 months of the subsequent calendar year in the form of the Annual Energy Charge.

Q. What distribution costs are included in the LTILR?

A. The LTILR contains a monthly distribution charge based on the dedicated distribution facilities in place to serve HSC. HSC pays the levelized cost of distribution for the service it is provided, which is depicted in Exhibit A-87 (HJM-68), Line 11 as a monthly charge of [redacted] per month. This is consistent with Section 10gg(1)(g) of Act 348.

Q. What happens if future investments are needed in the distribution facilities that serve HSC?

A. As discussed by Company witness Myers, the levelized cost of distribution was based on the original cost of investment in distribution facilities that serve the HSC site. Additional investments that might be needed for the distribution facilities are addressed in a facilities agreement for distribution service that remains in place along with the HSC contract, and the facilities agreement specifies the cost responsibility of the parties for future investment in distribution facilities.

Q. What transmission costs are included in the HSC Contract?

A. The Transmission Charge is based on the Company's costs to acquire transmission service to serve HSC's load. The monthly Transmission Charge is equal to the portion of the Company's transmission costs attributed to HSC's monthly load. The charge is determined based on HSC's contribution to the monthly peak demand, using determinants MISO uses to establish the transmission costs billed to the Company, plus a pro-rata portion of any MISO transmission credits or charges pursuant to the MISO Tariff.

Q. What is HSC charged for Reserved Capacity?

A. HSC is charged a Reserved Capacity Charge of [redacted]

Q. How was the Reserved Capacity Charge determined?

A. The Reserved Capacity Charge was set at the Capacity Charge Rate less the weighted average annual Monthly Interruptible Credit at the time the HSC Contract was executed and amended. By setting the Reserved Capacity Charge in this manner, total revenues collected through the Capacity Charge and Reserved Capacity Charge net of the Interruptible Credit will remain constant when HSC updates its election of Annual Forecasted Capacity, absent any changes to the Interruptible Credit.

Q. Please describe the requirements for Commission approval of a contract under the LTILR.

A. Section 10gg(3) of Act 348 states that the Commission "shall approve any contract for a term proposed by an electric utility under a [LTILR]... if there is a net benefit to the electric utility's customers resulting from the industrial customer taking service under the

[LTILR] compared to the industrial customer not purchasing standard tariff service from the electric utility."

Q. Does the HSC Contract provide a net benefit as defined in Act 348?

A. Yes. As supported by Company witness Miller, a net benefit exists because in taking service under the LTILR, HSC will contribute to the Company's fixed transmission costs that otherwise would have been recovered from the Company's remaining customers as compared to HSC not purchasing standard tariff service from the Company pursuant to Section 10gg(4) of Act 348.

Q. What is this total net benefit in the test year?

A. As shown in Exhibit A-77 (HWM-5), there is a net benefit of $11.3 million in the Company's fixed transmission costs in the projected test year.

Q. What is the total net benefit over the term of the HSC Contract?

A. As shown in Exhibit A-77 (HWM-5), there is a net benefit of $153.5 million in the Company's fixed transmission costs over the term of the contract.

Q. Should the Commission approve the HSC Contract for the term proposed by the Company?

A. Yes. The Company requests that the Commission approve the HSC Contract because HSC's contribution to fixed transmission costs indicates that a net benefit exists, and HSC otherwise qualifies for the LTILR.

<u>HSC CONTRACT REVENUES</u>

Q. What are the contracted rates for the Test Year?

A. The HSC Contract contains the following contracted rates as depicted in Exhibit A-73 (MPK-1):

1. System Access Charge in Line 1 of [redacted];
2. Monthly Capacity Charge in Line 2 of [redacted];
3. Monthly Reserved Capacity Charge in Line 3 of [redacted];
4. Monthly Interruptible Credit in Line 4 of $6.00/kW-month in the Winter and $7.00/kW-month in the Summer; and
5. Distribution Charge in Line 5 of [redacted].

Q. Are the previously-mentioned rates fixed through the term of the HSC Contract?

A. No. All of the charges have been defined in the HSC Contract and fixed for the term of the contract with the exception of the Monthly Interruptible Credit. The Monthly Interruptible Credit will remain equal to the credit provided under the Large General Service Primary Demand Rate GPD, Interruptible Service Provision (GI) which is subject to changes in future Company rate cases.

Q. Is the Monthly Interruptible Credit equal to what has been proposed for Rate GPD through the Interruptible Service Provision (GI) in the current rate case?

A. Yes. The Monthly Interruptible Credit is equal to the credit provided to Rate GPD through the Interruptible Service Provision (GI) as proposed by the Company in the current rate case and as shown in Exhibit A-16 (RLB-2), Schedule F-5.

Q. Is the Reserved Capacity Charge subject to change in future rate cases?

A. No, absent an amendment to the HSC Contract.

Q. What are HSC's capacity elections for the Test Year?

A. HSC has elected capacities as illustrated in Chart 6 below and depicted in Confidential Exhibit A-73 (MPK-1) for the test year:

1. Maximum Contracted Capacity of [redacted] MW in Line 6 of Confidential Exhibit A-73 (MPK-1): This is the maximum amount of electric capacity eligible for purchase by HSC under the HSC Contract;

2. Annual Forecast Capacity of [redacted] in Line 7 of Confidential Exhibit A-73 (MPK-1): This is the maximum amount of electric capacity that HSC forecasts it will require. It cannot be increased beyond the Maximum Forecast Capacity;

3. Firm Contracted Capacity of 100 MW in Line 8 of Confidential Exhibit A-73 MPK-1): This is the firm level of electric capacity that HSC forecasts it will require;

4. Reserve Capacity of [redacted] in Line 9 of Confidential Exhibit A-73 (MPK-1): The difference in capacity between the Maximum Contract Capacity and the Annual Forecast Capacity; and

5. Interruptible Service Capacity of [redacted] in Line 10 of Confidential Exhibit A-73 (MPK-1): The difference capacity between the Annual Forecast Capacity and the Firm Contract Capacity.

[redacted]

Q. How often can the capacity elections be updated?

A. HSC can update capacity elections as provided in the HSC Contract:

1. Maximum Contracted Capacity can be increased by written amendment to the HSC Contract but cannot be reduced below the originally agreed upon amount.

2. Annual Forecast Capacity is elected eight months prior to the start of the subsequent MISO Planning Year. HSC cannot elect an Annual Forecast Capacity below the lowest Annual Forecast Capacity occurring during the term of the HSC Contract, unless HSC provides one year's written notice and the MPSC approves a corresponding revenue requirement adjustment in a Company rate case.

3. Firm Contracted Capacity is elected eight months before the start of the subsequent MISO Planning Year. HSC cannot elect a Firm Contracted Capacity below the lowest Firm Contracted Capacity occurring during the term of the HSC Contract, unless HSC provides one year's written notice to the Company of its request to reduce the Firm Contracted Capacity and the MPSC approves a corresponding revenue requirement adjustment in a Company rate case. [redacted]

Q. Can HSC change its Annual Forecast Capacity election for the Projected Test Year?

A. Yes. HSC is still able to elect an increase in its Annual Forecast Capacity for the MISO 2021/22 Planning Year based on known and verifiable changes to its forecast. Additionally, if HSC's monthly demand increases beyond its election, the Annual Forecast Capacity is triggered to increase automatically.

Q. What is the projected revenue from the HSC Contract in the projected test year?

A. As depicted in Confidential Exhibit A-73 (MPK-1), page 2, line 20, the Company projects [redacted] in revenue, including surcharges, from the HSC Contract in the projected test year.

Q. What surcharges are included in the calculation of HSC Contract revenue?

A. As depicted in Confidential Exhibit A-73 (MPK-1), page 2, lines 13 through 18, the surcharges currently applicable to the HSC Contract are (1) Renewable Energy Surcharge; (2) Energy Efficiency Surcharge; (3) Power Plant Securitization; (4) Low-Income Energy Assistance Fund Surcharge; (5) Demand Response Reconciliation Surcharge; and (6) Electric Rate Case Deferral Surcharge.

Q. What is the projected revenue excluding surcharges?

A. As depicted in Confidential Exhibit A-73 (MPK-1), page 2, line 21, the Company projects [redacted] in revenue, excluding surcharges, from the HSC Contract in the projected test year.

Q. Please describe how you calculated the expected revenues from the HSC contract for the projected test year?

A. To calculate the revenues from the HSC Contract, and as shown in Confidential Exhibit A-73 (MPK-1), I first applied the [redacted] System Access Charge from page 1, line 1 for each month of the test year in page 2, line 1 to total [redacted] that HSC will pay in the test year. I then calculated the Power Supply Charges of [redacted] in page 2, line 5. To calculate the Power Supply Charges, I summed the following components:

- The Monthly Capacity Charge of [redacted] in page 2, line 2 is calculated by taking the Capacity Charge of [redacted] from page 1, line 2 and multiplying that by HSC's Annual Forecast Capacity of [redacted] in page 1, line 7;

- The Monthly Reserve Capacity Charge of [redacted] in page 2, line 3 is calculated by taking the Reserved Capacity Charge of [redacted] from page 1, line 3 and multiplying that by HSC's Reserved Capacity of [redacted] in page 1, line 9; and

- The Monthly Interruptible Credit of [redacted] in page 2, line 4 is calculated by taking the Interruptible rate of ($6.00/kW-month) for the eight non-summer months of the year and ($7.00/kW-month) for the four summer months of the year as shown in page 1, line 4 and multiplying those monthly amounts by HSC's Interruptible Service Capacity of [redacted] in page 1, line 10.

Next, I calculated the Monthly Energy Charge of [redacted]. The monthly energy charge is calculated on an hourly basis based upon HSC's forecasted consumption, the associated production at the Zeeland CCGT as provided by Company witnesses Breuring and Troyer, respectively, and market purchases as previously described in my testimony. For the projected test year, I calculated that HSC will pay [redacted] in Cost of

Production for the associated production at the Zeeland CCGT as shown in page 2, line 6, and [redacted] in Displacement Cost for the associated market purchases. I then adjusted these amounts for the Margin Credit in page 2, line 9 of [redacted]. The Margin Credit is calculated on an hourly basis for the year as described earlier in my testimony. I then included [redacted] in costs to provide transmission service to HSC in page 2, line 10 and made a credit adjustment of [redacted] for HSC's share of MISO Billing Charge and / (Credits) in page 2, line 11. I then included the monthly distribution charge of [redacted] from page 1, line 5 for the twelve months of the year to total arrive at [redacted] as shown in page 2, line 12. Finally, I included [redacted] in surcharge revenue that is expected to be collected in the test year as shown in page 2, line 17.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697

DIRECT TESTIMONY

OF

STEVEN Q. MCLEAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Steven Q. McLean, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Customer Experience Regulatory Strategy, Reporting and Quality in the Clean Energy Products Department.

Q. Please review your educational background.

A. I earned a Bachelor of Science in Political Science and Economics from Central Michigan University in May 2003. I earned a Master of Arts in Economics from Central Michigan University in December 2007.

Q. Please review your business experience.

A. In January 2006, I joined the Michigan Public Service Commission ("MPSC" or the "Commission") where I held various positions of increasing responsibility. In 2011, I was promoted to the Manager of the Rates and Tariffs section. The responsibilities of that section included, but were not limited to, analyzing utility reports, financial records, and rate case filings to determine the appropriate level of rates for regulated energy utilities utilizing laws, regulations, and Commission policies. In August of 2014, I was hired by SEMCO Energy Gas Company ("SEMCO") as the Rates and Regulatory Affairs Manager. In December of 2016, I was promoted to Director of Regulatory Affairs. As Director of Regulatory Affairs, I was responsible for all state and federal regulatory matters for SEMCO. In addition, I was responsible for the Company's Energy Waste Reduction program. In September of 2019 I was hired by Consumers Energy as the Director of

Customer Experience Regulatory Strategy, Reporting and Quality within the Clean Energy Department.

Q. What are your responsibilities as the Director of Customer Experience Regulatory Strategy, Reporting and Quality?

A. In this position I am responsible for coordinating the regulatory filings, reporting, and quality processes associated with the Company's Energy Waste Reduction Plans, Voluntary Green Pricing programs, and residential Demand Response ("DR") programs. In addition, I am responsible for supporting all Customer Experience related expenses and capital investments in gas and electric general rate cases.

Q. Have you previously testified before the MPSC?

A. Yes. I have testified before the MPSC in numerous general rate cases, Gas Cost Recovery cases, Energy Waste Reduction cases, and other miscellaneous proceedings on behalf of the MPSC Staff and SEMCO. In addition, I filed testimony on behalf of the Company in Case No. U-20650, which is the Company's most recent gas general rate case.

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

A. The purpose of my direct testimony is to describe: (i) Customer Experience & Operations ("CX&O") and how the work performed within this organization benefits the Company's residential and business electric customers today and into the future. This includes a proposal for a new Low Income Assistance Credit (”LIAC”). As part of my direct testimony I will also address the Operations and Maintenance ("O&M") expenses and capital investment associated with executing this work in the test year ending December 2021; (ii) the Company's DR program, including O&M expenses and capital expenditures. In addition, I am supporting the Company's proposal for a DR surcharge to address over/under collections and recovery of any performance incentive during the reconciliation process.

Q. Please describe CX&O.

A. In short, CX&O comprises three areas that collectively define the experience electric customers have when interacting with the Company. These include: (i) using established data analysis techniques to understand, communicate, and engage with the Company's electric customers in an impactful way (Customer Analytics and Outreach); (ii) connecting with electric customers in the channel (phone, text, and email) they prefer today, while enhancing the Company's digital resources in response to growing customer feedback that they prefer "self-serving" through digital channels (Customer Interactions); and (iii) providing customers accurate, timely energy bills and consistent payment processes (Billing and Payment). While I will describe each of these areas in turn, it is through the collective efforts of these areas that (i) cost savings will be realized; and (ii) customers will decide whether they were satisfied when interacting with the Company.

Q. How is customer satisfaction measured by the Company?

A. Historically the Company relied on JD Power as the primary measure of customer satisfaction. While the JD Power results still provide valuable quarterly feedback from customers, the Company realized it needed a real-time measure of its performance to keep pace with customer expectations. As such, the Company is using the Customer Experience Index ("CXi") score developed by Forrester, along with customer feedback through JD Power and internal customer research, to improve its agility in responding to customer feedback.

Q. Please describe the CXi score and why the Company is using it as the primary metric for measuring customer experience.

A. The CXi score is a common customer experience survey framework that measures the customer perception of an interaction. The framework consists of three questions: How well did the Company meet your needs, was it easy, and was it enjoyable? Through these three simple questions, the Company gains insight into a more complete picture of the overall customer experience and can use near real-time feedback to prioritize and focus its work as part of improving its interaction with customers without waiting for quarterly JD Power results to see if an initiative has worked. As an example of how CXi is used, assume a customer is in the process of moving and wants to schedule a move-in and create an account online. The customer locates the online application, but for some reason cannot make the update and receives a message to call a customer service representative who makes the proper arrangements in quick fashion. In this scenario the Company would have met the customer's need of updating the account, but it was not easy. Another example is the importance of effective communication during an outage. Assume that a customer visits the website to report their outage. If they have previous online authentication or if they are visiting us from a county with multiple customers reporting an outage, they are automatically redirected to the Outage Center. Within the online outage center, they are able to report their outage, sign up for outage alerts to receive restoration updates, view outage status and cause, and get important restoration and weather information to help keep them safe during their outage situation. In this scenario, the Company met the customer's need, made it easy for the customer to report and track the restoration efforts, and provided the necessary and timely information to the customer. While it is certainly not enjoyable to lose power, the Company seeks to communicate with customers in their preferred channel and provide the most accurate and up-to-date information until power is restored safely.

Q. Is the Company proposing to use the CXi across all "touchpoints" with customers?

A. Yes, the Company has created a standard system for tracking and reporting the CXi scores across its call centers (phone and Interactive Voice Response systems) and digital interactions with customers. As part of this process the Company also continually refines its measurement of the CXi scores to ensure it is accurately capturing customer sentiments across all channels.

Q. Please describe the Company's CX&O focus.

A. Historically, there has not been a significant emphasis on being a "retailer" for customers. However, given the changes in customer behavior and the Company's desire to be a cleaner and leaner utility, the Company needed to change how it interacts with customers. The Company is transforming its service methodology in accordance with the changing behaviors and needs of customers. This includes introducing enhanced clean energy products to meet the needs of customers and the environment. The CX&O strives to make interactions fast and simple for customers in order to encourage them to choose the Company's clean energy products in the future. This framework includes success metrics and long-term technology and program offerings that the Company must implement to meet these objectives.

Figure 1

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-12 (SQM-1)	Schedule B-5.5	Projected Capital Expenditures – Customer Experience & Operations;
Exhibit A-75 (SQM-2)		Projected Customer Experience and Operations O&M Expenses & Revenues Summary; and
Exhibit A-76 (SQM-3)		Customer Experience and Operations IT Project Summary.

Q. Please describe Exhibit A-12 (SQM-1), Schedule B-5.5.

A. Exhibit A-12 (SQM-1), Schedule B-5.5 details the capital expenditures related to work within the CX&O organization, which total $49.9 million, $36.9 million of which is to support electric DR, from 2019 through the test year ending December 31, 2021.

Q. Please describe Exhibit A-75 (SQM-2).

A. Exhibit A-75 (SQM-2) details the O&M expenses related to work within the CX&O organization, which total $88.7 million, $34.7 million of which supports electric DR, for the test year ending December 31, 2021.

Q. Please describe Exhibit A-76 (SQM-3).

A. Exhibit A-76 (SQM-3) describes the Information Technology ("IT") projects supporting the CX&O organization along with a summary of the corresponding test year capital and O&M costs contained in the exhibits of the Company's IT witness Jeffrey D. Tolonen.

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

A. Yes.

Q. Please discuss any changes to the structure of the organization since the Company filed its last electric rate case.

A. There have been no major changes to the structure of the CX&O organization in 2018 or 2019. There has been some minor shifting of responsibilities both within the CX&O organization and other organizations within Consumers Energy, which I will describe later in my testimony.

Q. Please provide a summary of the CX&O expenses and capital investment projected in the test year.

A. CX&O is projecting $88.7 million in O&M expense for the test year ending December 31, 2021. This amount comprises $54 million of O&M for Analytics and Outreach, Customer Interactions, and Billing and Payment; and O&M of $18.9 million for residential DR and $15.7 million for Commercial and Industrial ("C&I") DR. The CX&O O&M expenses are illustrated on Exhibit A-75 (SQM-2). The Company is also projecting $49.9 million in capital investment through the test year to support the CX&O infrastructure development and DR initiatives described below and outlined in Exhibit A-12 (SQM-1), Schedule B-5.5.

I. <u>ANALYTICS and OUTREACH</u>

Q. Please provide an overview of the Analytics and Outreach area and any recent structural changes.

A. The Analytics and Outreach work is performed by two separate teams and can be broken down into four major categories: (i) Customer Research; (ii) Data and Analytics; (iii) Customer Experience Design; and (iv) Operational Communications. Previously, Analytics and Outreach included the Communications and Outreach function which develops the strategy, media buying, and creative material to communicate with customers on topics such as safety, improvements in the electric system in customers' communities, and assistance programs to help manage their bills. This function has been consolidated into the Corporate Communications organization. Operational communications have been moved from the Corporate Communications organization to Analytics and Outreach as part of a new team dedicated to Customer Experience Design and Operational Communications. To effectively perform in the Analytics and Outreach functions, the Company is projecting $5.5 million of O&M expenses for the test year ending December 2021, as shown on Exhibit A-75 (SQM-2), page 2. This represents no significant change from the $5.5 million expended in 2018. The Company is also projecting $11.8 million of capital expenditures through the test year, as shown on Exhibit A-12 (SQM-1), Schedule B-5.5. This capital investment is related to several projects which will increase the Company's ability to understand, serve, and communicate with customers. These projects also include approximately $900,071 of the $5.5 million of projected O&M expense. The projects are discussed in greater detail below. I will discuss the four major functions of Analytics and Outreach, and related projects, in two separate sections: (i) Customer Analytics; and (ii) Customer Experience Design and Operational Communications.

A. Customer Analytics

Q. Please provide an overview of Customer Analytics.

A. Customer Analytics is the business process of creating relationships with and satisfying customers. Consumers Energy is focused on better understanding our customers, being more predictive about their needs, and becoming more personalized in the customer experiences they have with Consumers Energy. The expected results of these efforts are reduced costs and increased efficiencies for both the customer and the Company. Customer Analytics considers:

- **What Programs to offer**: Use of primary and secondary customer research to understand and inform the experiences, utility programs, and services to develop;
- **Who to target**: Develop advanced analytics models to identify target customers based on demographic/firmographic data, customer insights, and other customer specific attributes; and
- **How to engage customers**: Develop customer engagement that is outside-in focused, meaning it is built with the customer needs first, based on feedback received, to meet the needs of customers, based on specific customer preferences.

Q. Please describe the type of work performed in Customer Analytics.

A. Much of this work can be categorized into two areas of focus: (i) customer research; and (ii) customer analytics. The Company is undertaking several projects which will increase customer feedback and develop advanced analytics models to improve the Company's ability to serve customers. Projected test year O&M expense for these projects is approximately $0.4 million which is included in Exhibit A-75 (SQM-2). And to support the critical work of customer analytics, the Company is projecting $7.5 million in capital investment through the test year, as shown on Exhibit A-12 (SQM-1), Schedule B-5.5, page 3. Table 1 below details the Customer Analytics projects.

Table 1 – Analytics & Outreach Investments
($ in Dollars)

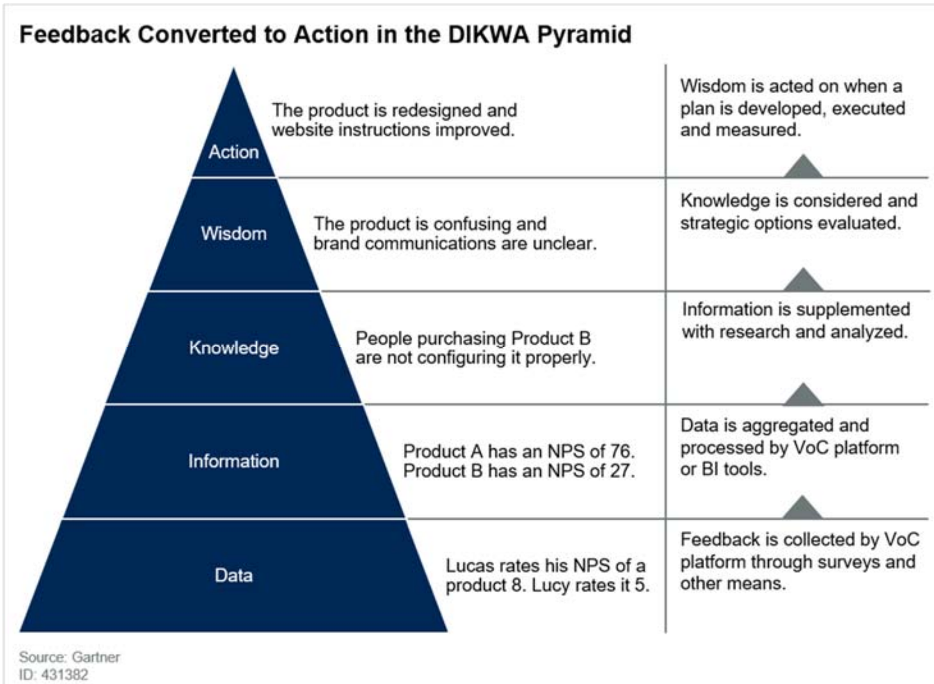
Category	Description	O&M	Capital
CUSTOMER RESEARCH		$130,050	$670,000
A. Voice of the Customer	A new technology platform and process to manage and integrate customer research, customer feedback, and customer comments into one Voice of the Customer solution. This solution will enable a more holistic view of the customer, their needs and service expectations. The data and insights derived from this will improve the outreach outcomes when promoting utility products and services, as well as improve the contact center experience.	$130,050	$670,000
CUSTOMER DATA & ANALYTICS		$311,021	$6,867,966
B. Advanced Analytics Hub	Measuring the impact of communications, outreach, and engagement on utility products and services and overall customer experience. This includes being able to predict the next best service to offer a customer based on their past engagement, and measuring the effectiveness of communication messages and channels to individual segments.	$44,625	$1,949,996

C. Customer Relationship Management ("CRM")	CRM technologies support the ability to identify and manage customer relationships, in person or virtually. CRM software provides functionality to companies in four segments: customer service, digital interactions, sales, and marketing.	$266,396	$4,917,970
Total		**$441,071**	**$7,537,966**

Q. Please describe the Voice of the Customer ("VoC") technology platform and process?

A. Advancements in customer technology and customer expectations are continuing to shift the energy industry landscape. Customer data and feedback such as surveys, social media comments, and conversations with contact center representatives are generated through customers' interactions with various different teams within the Company. This data and feedback is reviewed daily by operational teams to identify issues, customer pain points, and opportunities to improve the overall customer experience. Using this data and feedback has helped the Company reduce over 1 million calls from our contact center since 2017 as well as reduce formal complaints more than 20% since 2017. However, the Company does not currently have the ability to integrate all of the customer data and feedback received from the various channels at a customer record level. The dispersed nature of the data limits the Company's ability to effectively incorporate customer feedback and continue to reduce calls and formal complaints. This new VoC technology platform will bring all of the data and feedback together allowing the Company to better understand customers' feedback across any and all channels leading to better customer understanding and engagement. This new platform provides a foundation for the Company to obtain and organize customer data necessary to address existing issues and create innovative, differentiated experiences. Below is an illustration of how customer feedback, or the VoC data, is used to improve an experience, the communications, and the customer outcomes.

Figure 2



VoC will provide increased visibility into customer expectations and experiences. This will allow the Company to better collect information from customer interactions and analyze it to identify the best opportunities and area of focus which will have the greatest impact on improved customer service.

Using information from leading research firms such as Gartner and Forrester, the Company will develop best practices, identify surveys and research needs, obtain the right data to produce the necessary analysis, and provide the customer information that the customer needs and values. The Company's VoC efforts will drive key aspects of a good customer experience management program to improve the Company's service to customers. VoC will:

- **Improve Customer Experience** – VoC data is used to fuel a collaborative process to improve the end-to-end customer journey. Data is used by cross-functional Customer Experience ("CX") teams to understand the needs of customers and the Company's success in meeting those needs. Key considerations include drivers of customer satisfaction and dissatisfaction, as well as the financial impact of improved satisfaction, loyalty, and advocacy;
- **Close the Loop** – VoC data is used to drive granular action at a customer-by-customer level. Individual customer responses are evaluated for targeted action, typically when a customer expresses strong dissatisfaction or satisfaction;
- **Improve Customer Activation** – VoC data is used to support efforts to gain a single view of the customer and execute strategies that deliver greater engagement. Customer feedback can be combined with operational and other data and used to drive personalization and other customer activation strategies; and
- **Uncover Risks** – VoC data is used to listen, identify, and act early on potentially costly risks. Customer survey and listening data can be monitored to uncover issues that might grow into damaging problems, such as data or security risks.

Customer Analytics and VoC technologies were the biggest investments for CX improvement projects in 2018 and are expected to increase.

Forrester has also identified the role that VoC has in the Company's CX maturity. The table below identifies the competency and the outcomes the Company expects from this VoC platform:

Figure 3

Discipline	Relationship to VoC
Research	Insights about customer attitudes and behaviors help guide qualitative research efforts that produce tools like personas, customer journey maps, and CX ecosystem maps.
Prioritization	VoC programs guide organizations on where to focus by identifying what is most important to the customers' experience and the business' success.
Design	The ultimate design of an experience flows from the organization's CX vision and the insights from its research discipline, which are both influenced by data from the VoC program.
Enablement	The VoC program helps organizations tune technology, processes, and procedures for employees and partners, ensuring that the actions those people take deliver customer value. This is because it provides managers with a way to collect customer observations on the health of the journey.
Measurement	Through surveys, VoC programs capture the solicited, structured data that provides metrics for customer experience measurement programs.
Culture	Customer stories and verbatims gathered by the VoC program can bring the customer experience to life and help create a customer-centric culture.

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Q. Are you aware of other regulated utilities investing in customer research?

A. Yes, utilities across the county are investing in research to better understand the voice of their customers. The Company has spoken directly with two utilities that have successfully implemented VoC utility technology platforms:

- Southern California Edison leverages a VoC system to present customer feedback to their operations employees, driving actionable insights for those employees to improve the customer experience. Since implementing in 2017, they have found the system allows for more real-time feedback from customers with transactional experiences driving quicker action internally. As a result, their Net Promoter Score ("NPS"), which measure how likely customers are to recommend a company to a friend for transactions, improved approximately 10 points one year after implementation; and

- Duke Energy is also using a VoC system to identify opportunities to improve customer satisfaction, quantify and validate opportunities with operational measures, and develop recommendations to enhance the customer experience.

Q. Please describe the customer data and analytics projects.

A. The Company is projecting costs to continue to build an advanced analytics hub and implement a new CRM technology platform. These efforts are foundational in order to offer the right customer experience, to the right customer, in the right channel, at the right time. Salesforce's study[1] on customer expectations concluded that:

- 84% of customers say being treated like a person, not a number, is very important;
- 70% of customers say understanding how they use products and services is very important;
- 59% of customers say tailored engagement based on past interactions is very important;
- Customers are twice as likely to view personalized offers as important versus unimportant; and
- 67% of customers say their standards for good experiences are higher than ever.

The Company recognizes this shift in customer expectations and is expanding the role of data and analytics in order to better understand the complexity of data, the number of variables to be analyzed, the types of analysis, and the speed of the analysis required to produce better outcomes for customers.

It is not enough for the Company to merely know the consumption patterns of customers, the way customers pay their bill, and the demographic (or firmographic for businesses) data. Customers expect the Company to understand their needs and the impact

[1] Source: Salesforce, "Customer Expectations Hit All-Time Highs" https://www.salesforce.com/research/customer-expectations/

of their behaviors on their bill, and to provide personalized recommendations for what to do next. This requires the Company's analytics capabilities to evolve from descriptive analytics – understanding what happened historically – to predictive analytics – being able to predict what will happen next. These more advanced analytics capabilities include propensity modeling, machine learning, and artificial intelligence.

These analytics support actionable recommendations for which utility products and services are right for a specific customer segment. This may include customer recommendations such as paying a bill a certain way, changing to a different rate that is better suited for their energy needs, and alerting customers to higher consumption patterns that may yield a higher bill and then tailoring actions to help them reduce their bill. Additionally, these analytics will provide insights into what communications and customer touchpoints are driving the greatest customer benefit. An example of this is the insight these capabilities are producing for the Summer Time-of-Use ("TOU") rate pilot outreach. The Company is able to assess which communication channels and which frequency level of communicating drives favorable customer outcomes for each customer segment (such as low income and seniors). The Company will be able to predict with greater accuracy the communication types and costs necessary by segment to ensure customer communications are efficient and effective.

Q. Please describe the CRM technology platform.

A. The CRM technology platform will ensure that the data is accessible to those within the Company that need to access the information. The Company currently does not have an enterprise CRM solution focusing on customer and marketing analytics. This limits the Company's ability to efficiently identify products and programs for customers to support

DR efforts. CRM is a technology for managing all relationships and interactions with customers. This technology platform connects customer care, account management, customer activation, and customer acquisition for products and services. This will permit anyone in the Company that needs to (and has access rights) to view the complete customer relationship including what has been offered to them, service issues, programs they are engaged in, and usage patterns. Customers may be contacting you on a range of different platforms including phone, email, or social media — asking questions, following up on orders, or contacting the Company about an issue. Without a common platform for customer interactions, communications can be missed or lost in the flood of information, leading to a slow or unsatisfactory response. The CRM solution will permit the Company to integrate with existing software solutions to create a Company-wide tool for supporting customer relations. The Company will be able to compare marketing data with customers' energy usage and other datasets, which the Company expects to lead to improved programs and increased customer enrollment in Company programs such as DR. The project is expected to add the following value:

- Program Enrollment Growth;
  - Increase effective customer communication;
  - Increased program enrollments; and
  - Increased customer activation through campaign automation.
- Operational Efficiency and Productivity Improvements;
  - Decreased customer acquisition cost into programs;
  - Enhanced visibility and optimization of campaign spend;

  - Decreased program administration cost;
  - Decreased data entry time;
  - Decreased data extraction and manipulation time; and
  - Decreased report creation and maintenance time.
- Cost optimization through system consolidation of siloed CRM instances; and
- External vendor costs reduction.

Q. Can you provide examples of operational benefits from a CRM?

A. Yes. Based on the 2019 Residential Electric J.D. Power results, customers are much more satisfied when they are proactively contacted by the Company with outage related information. Satisfaction is 12% to 16% higher when a customer receives proactive communication from Consumers Energy, than if they need to call the Company to obtain that information. Also, the Company measured customer perceptions of outage response during storms that occurred in October 2019. Three types of proactive communications were assessed: (i) preparation communications prior to storm arrival; (ii) communication during the outage; and (iii) communication provided after restoration. CXi scores were substantially higher if customers received at least two of these three communications (72 or higher) compared to those who did not receive any of these communications (24). A CRM platform will provide accurate and integrated customer contact data to enable the Company to inform and prepare customers for impending major events in a systematic manner. This will significantly improve the Company's ability to reach a broader audience and improve customer experience during outage situations.

Q. Are there other examples of how a CRM can benefit the Company and its customers?

A. Yes. It recently came to the Company's attention that some customers are receiving excessive communications over a short period of time. This is the result of a lack of comprehensive information regarding customer communications to any individual customer. A CRM will provide accurate and integrated information regarding customer communications which will allow the Company to limit and target communications to provide customers with the information they need without overwhelming them.

Q. What is the scope of the CRM Project?

A. The project includes implementation of modules for Account Management, Sales Life-cycle Management, Product and Program Management, Marketing and Campaign Management, Centralized eligibility and enrollments, Service Quality Management, Partner Management, Consolidated Preference Center, and Common Platform. The project will maintain customer information related to their account and activity, maintain process flow for programs enrollment and services, and maintain inventory of programs customers have participated in; integrate with the Company's existing Supply Chain product (SAP); identify and maintain campaigns for various customer segments across all channels, maintain eligibility and business rules for programs, maintain and manage customer contacts related to issues, maintain partner inventory/roster including metrics, maintain all customer preferences for communications, notifications, and alerts within a single repository, and include the ability to connect/integrate with a number of third-party applications and internet of things.

Q. Has the Company evaluated alternatives to the CRM Project?

A. Yes. Those alternatives include: (1) hiring additional staff to complete data retrieval, consolidation, and updates for each customer interaction, thereby requiring additional cost of 10 new employees' salary and benefits; (2) customizing (build your own) internal applications to hold additional data including integration points, datastores, modification of business processes, and increased maintenance costs; and (3) continuing with the current process, which will continue to create waste and additional costs, leading to a reduction in customer experience and fewer opportunities for enrollment in utility products and services. These options were less cost effective and were not chosen because they would require the Company to add additional employees, increase maintenance cost, or continue to face the risk of system-wide issues when errors occur.

Q. Are you aware of other utilities investing in analytics and CRM technology?

A. Yes, utilities across the country are investing in improved analytics capabilities and CRM technology to better understand customer opportunities and deliver a better customer experience. A few examples include:

- San Diego Gas & Electric Company launched their Customer Information System project in 2017 and subsequently discussed the program with Consumers Energy. They recognized that evolving market and customer demands are driving immediate needs in their analytics and technology capability. Some of those demands included:
    - Customers expect an experience comparable to top retailers;
    - On-demand service through digital channel of the customers' choice;
    - Personalized communications and offers;

- Exponential increase in data volume;
- Expanding customer choice and options; and
- Complex rates and programs introduced at rapid pace.

Examples of some of the benefits that they realized were:

Figure 4

Customer Benefits		**Operational Benefits**	
Previous State:	**Future State:**	**Previous State:**	**Future State:**
Complex interactions with utility Customer experience across platforms and channels can be siloed Lengthy time to implement new products and services Limited personalized recommendations	Simplified interactions with utility Communicate with utility through any channel consistently Quickly implement programs and customer options Tailored customer experience	Manually intensive back office processes Static customer engagement processes Inflexible, customized systems	Automated / streamlined modern processes Personalized and more efficient processes Agile, configurable vendor products

- According to SAP, other relevant utilities in North America leveraging their CRM platforms include Duke, Sempra, Southern California Edison, Southwest Gas, First Energy, Navajo Tribal, Florida Power and Light, Centrepoint Energy, Puget Sound Energy, and Hawaiian Electric.

Utilities that have implemented a CRM technology platform have indicated that they realized the same benefits and outcomes, such as:

- Decreased customer acquisition costs by approximately 20% through integrated data, insight driven customer outreach, and activation into operational and demand side programs;

- Increased number of customer activation campaigns by approximately 10%;

- Increased program enrollment by approximately 25% as a result of more prospects converting to demand side program enrollments;

- Decreased program administration costs by approximately 50% through consolidation of multiple solutions and integration of disparate data silos with a streamlined application process;

- Reduced system maintenance costs by approximately 25% through avoided costs of maintaining older, end of life applications, software licenses, and system decommissioning; and

- Reduced the time to market for new programs by approximately 15% with advanced analytics and product lifecycle management.

B. Customer Experience Design and Operational Communications

Q. Please describe the functions of the Customer Experience Design and Operational Communications area.

A. This area has three core responsibilities:

(1) Experience design services identify and remove customer interaction pain points and demonstrate customer centricity by making processes more efficient, modifying business rules, and creating user-friendly interactions. This team applies leading customer-centric practices, such as design thinking, iterative design, co-creation, and journey mapping to better understand customer needs and quickly identify and test potential solutions. These services are provided by Experience Managers who are responsible for strategic end-to-end interactions, prioritization of customer value improvement initiatives, and advocating for design and implementation of approved projects.

An example of this role is the Outage Experience Manager, who is responsible for improving Company outage restoration practices through improvements in people, process, and technology. The Experience Managers research and introduce customer satisfaction metrics into various processes and direct attention to improvements that will drive efficiencies and help realize service improvements that customers value. In 2019, CXi tracking led to the Outage Experience Manager introducing more customer-centric Estimated Time of Restoration ("ETR") performance metrics (see Figure 4) that have driven priorities in process and communication improvements. This understanding and the resulting changes to how ETRs are used have resulted in significant outage CXi gains in September and October of 2019 (see Figure 5) and have demonstrated the value of weather and outage communications pre-, during, and post-outage (see Figure 6). Figure 6 compares CXi for those customers who recall outage communications pre-, during, and post-outage to those who do not recall communications.

Figure 4: Estimated Time of Restoration (ETR) metric improvements

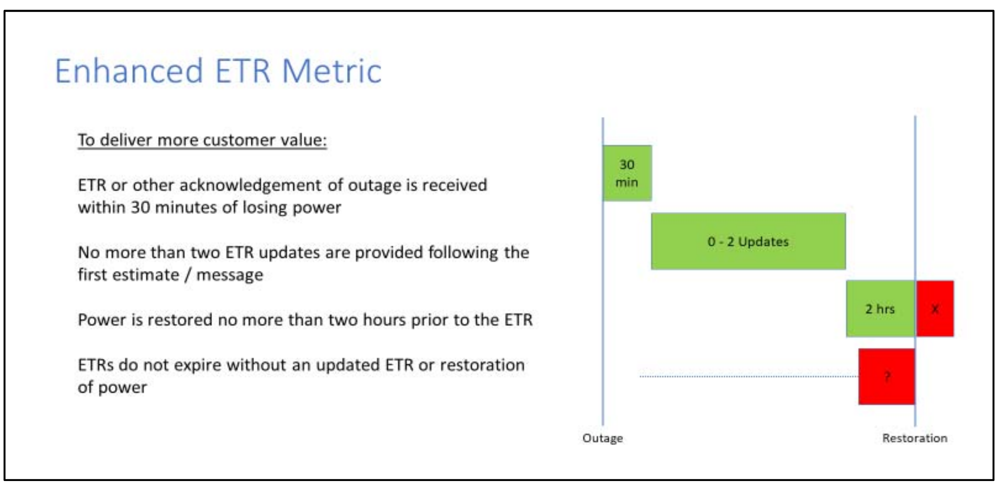


Figure 5: Weekly 2019 Outage Experience CXi Trend illustrates improvements after new outage metrics and communications standards are introduced in late July

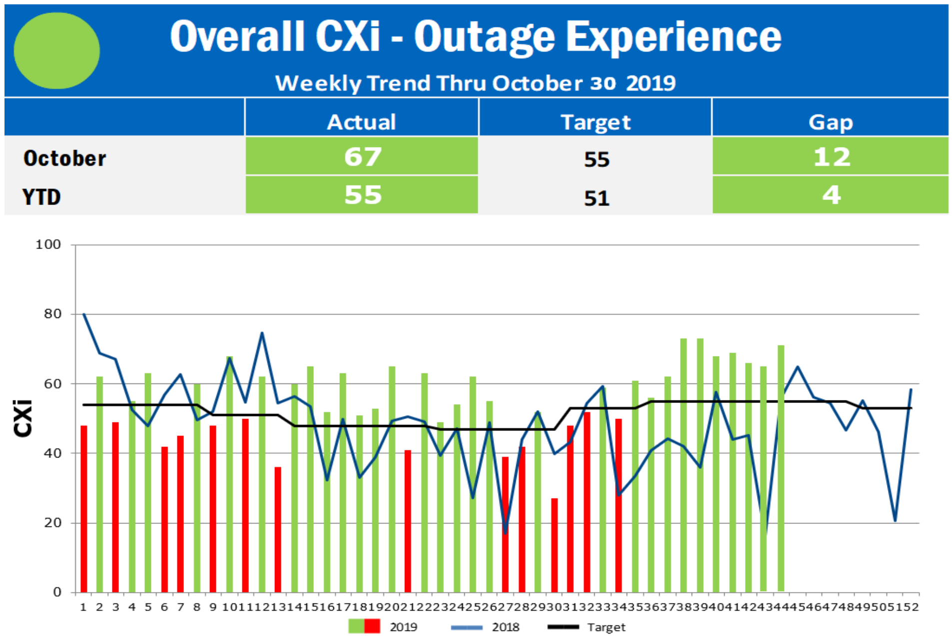


Figure 6: Survey of customers who lost power during October 2019 storm

Pre Outage	During Outage	After power restoration	CXi
Yes	Yes	Yes	81
No	Yes	Yes	77
Yes	Yes	No	72
No	Yes	No	47
Yes	No	No	24
No	No	No	24

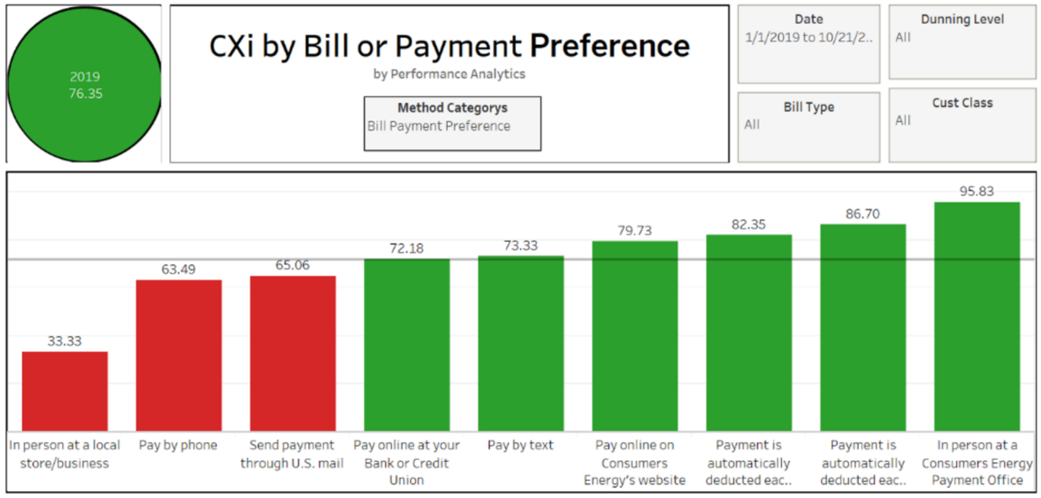
The Experience Manager also identifies and designs transformational improvement opportunities by using proven design practices that identify core problems and create ground-up solutions that achieve project goals. Within the outage experience, this includes the Outage Center's restoration service tracker, which was created using the design thinking process that includes joint interviews with internal stakeholders and customers. Input from various stakeholders can assist in producing solutions that address the needs of all parties, followed by rapid cycles of prototypes and testing.

(2) Product Managers are responsible for the operational quality and continuous improvement of established products and services. These individuals monitor, proactively test, and manage improvements to products and tools such as the Interval Web Portal, Budget Plan, and multiple payment options. This helps ensure that customer products and services are operating as designed and with maximum efficiency, continue to meet customer needs and expectations, and stay current against industry performance benchmarks. This team is critical to ensuring problems are identified early and resolved quickly, often before customers are aware an issue exists.

The payment product owner role, for example, makes sure that all customer payment options are working as intended on a daily basis. This role researches areas for improvement, designs and tests new solutions, and assumes a leadership role to implement approved projects. This role is also Chairperson of a Payment Council within the Company, which includes participants from Treasury, Finance, Billing Services, and Operational teams. The Council recently sponsored a cross-discipline project to improve the process of payment refunds, resulting in improved customer satisfaction, reduction of 3,500 calls annually, labor efficiencies estimated at 2,000 hours annually, and an annual cost reduction of $9,000 in bank fees.

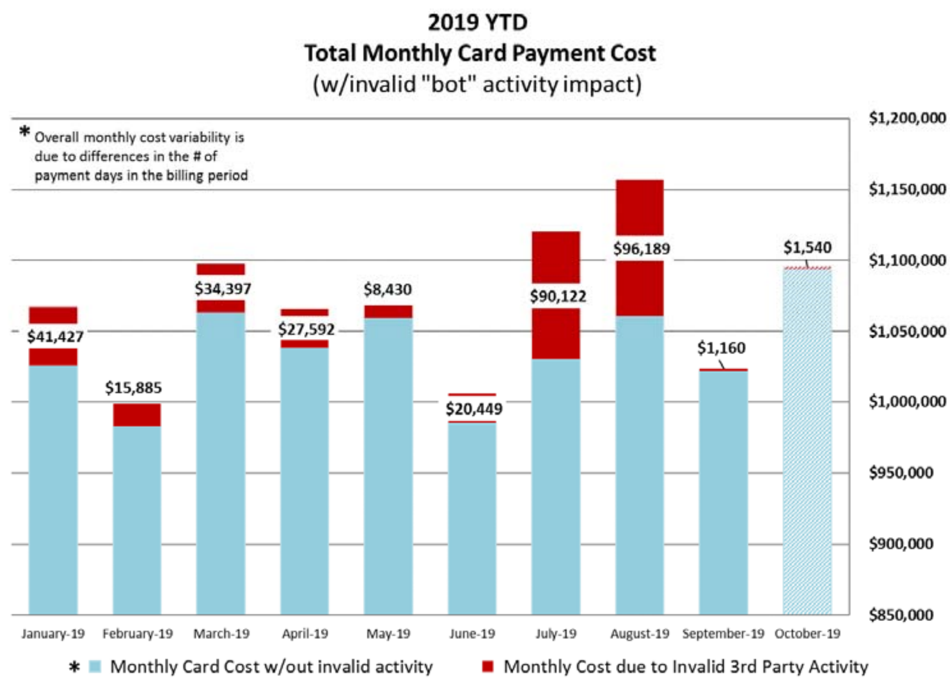
While the Payment role has been in place longer than some of the others and is unique to the area of specialty, the nature of the work is indicative of the overall role of the Product Owner team. The Payment Product Owner leads investigation of satisfaction issues across all payment options to identify opportunities for improvement (see Figure 7). The Payment Product Owner advocates for improvement projects and plays a leadership role in the design and implementation of such initiatives.

Figure 7



Current initiatives include pursuit of a "no fee" payment policy and priority projects detailed within the Customer Payment Program testimony below. The Payment Product Owner also investigates payment activity that violates terms and conditions and leads intervention activities. In July and August of 2019, the Payment Product Owner identified a surge of unauthorized payments and led actions to interrupt the activity (see Figure 8).

Figure 8



The Payment Product Owner documents payment behavior trends and forecasts future shifts in payment behavior to ensure the Company is prepared to provide payment services that customers expect in the future. The Payment Product Owner also implements the Customer Payment Strategy, which is detailed later in my testimony.

The Payment Product Owner manages our payment budget and vendors, monitors compliance with payment processes, and investigates customer and operational issues that involve the vendor network.

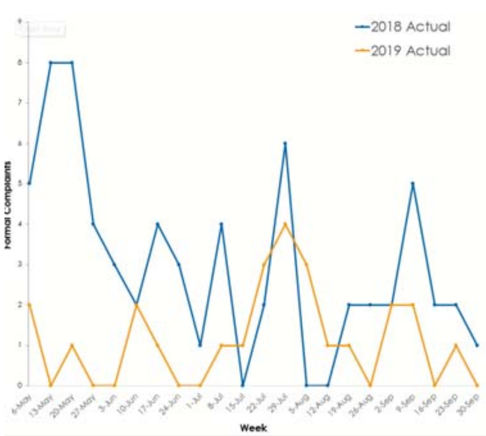
(3) Operational Communications manages turn-key communication standards and solutions for ongoing customer-facing utility operations. This includes identifying customer expectations, designing and testing communication solutions, documenting and socializing standards, and implementation across key operations. Examples of solutions developed and implemented during 2019 include electric infrastructure projects, extreme

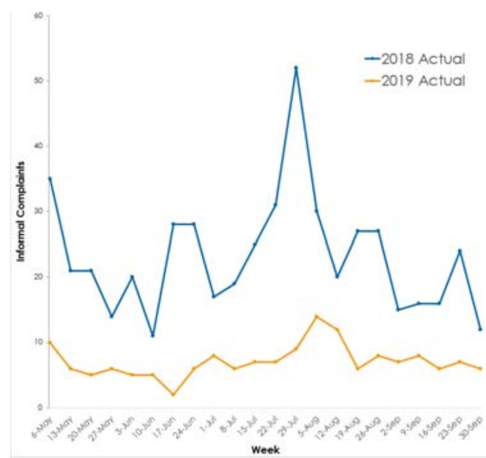
weather/high bill communications, and outage communications. Figure 9 below shows examples of customer communications. Providing customers with information on topics that can impact their usage within multiple channels (mail, email, social media) is necessary and important for customer satisfaction and understanding of Company operations.

Figure 9 – Customer Communications

Operational Communications work often involves close coordination with Experience Managers when designing new processes and with Product Owners for execution, or improvement of, existing communications. In the case of extreme weather/high bill communications, a standard process that was recently implemented includes monitoring weather and resulting billing patterns to activate communications that have been proven over the last year to help inform and educate customers in advance of receiving higher bills associated with seasonal weather changes and temperature extremes. This helps customers avoid surprises by offering advance notice with options to help control energy expenses. This simple process mitigates the impact of potential customer dissatisfaction, complaints, negative public sentiment, and operational impacts that are otherwise experienced during these times. In the 2019 summer extreme weather season, the Company communicated within nine channels ranging from customer direct email to social media resulting in 75% fewer informal complaints and 55% fewer formal complaints when compared to the previous year. This is illustrated in Figures 10a and 10b below.

<u>Figures 10a & 10b: Historical Formal and Informal Complaints by Week</u>





Together, the Experience Design and Operational Communications team plays a critical role in ensuring the Company understands what customers want and expect, prioritizing needs and project opportunities to deliver the most value possible, and leading the design, build, and implementation of customer-centric initiatives to achieve sustainable, long-term operational and customer satisfaction results.

Q. Is the Company projecting additional funding in this case to support the proposed work in the test year for Experience Design and Operations communication and outreach projects?

A. Yes. In support of improving customer experiences and satisfaction, the Company is projecting $0.5 million in O&M and $4.2 million of capital for customer experience improvement and communication related projects, detailed in Table 2 below. Customer feedback is integral within the design and implementation of new offerings and products and the Company will continue to solicit customer feedback using focus groups and facilitated user testing sessions.

Table 2 – Customer Experience & Communication Projects

Project	Description	O&M	Capital
Online Communication and Service Enhancements		$0	$4,233,000
Online Work Scheduling	This project will provide the ability for customers to be able to self-serve in making an appointment for work, eliminating the need for them to call to schedule.	$0	$1,020,000
Service Tracker	This project provides greater transparency into the status of work orders (service connection/turn on, etc.) from initiation to completion. It is designed to provide customers timely and accurate updates, including work order status and identification of arrival of field worker at the service location.	$0	$2,040,000

Streetlight Application	This project will provide an improved customer experience for those customers who need to report a streetlight outage including providing information on ownership, prioritization, and restoration status.	$0	$1,020,000
Alert Upgrades	System upgrades to the existing alert platform will provide direct control and additional flexibility that allow faster and more accurate of notification tools. It will also allow the creation of new alerts to improve customer communications, including provision of notifications for past-due and dunning communications.	$0	$153,000
Promotion of Self Services		$127,500	$0
Move In/Move Out Initiative	The purpose of this is to work with local real estate agents, builders, customers, and communities to educate and engage with the Company's improved online customer move in/move out process.	$127,500	$0
Outage Experience Improvements		$331,500	$0

Storm Activations and Content	Planning and implementation of volunteer-supported customer activation events that provide needed supplies and support to the public during storm and extreme weather situations. This includes resources necessary to update website content that will provide greater transparency into the restoration process and status.	$25,500	$0
Storm Communications	Storm communication templates and development of execution standards. These are necessary to operationalize the communications tests that were conducted in 2019 that resulted in significant improvements in customer experience and operational metrics.	$306,000	$0
Total		**$459,000**	**$4,233,000**

Q. Please describe the Online Communication and Service Enhancements.

A. The Online Work Scheduling Project will allow customers to request and schedule short-cycle work (such as service connection and flickering lights) online instead of requiring a call to the contact center. The online work scheduling application will allow customers to see the available timelines for scheduling and provide self-service capabilities for customers to select the timing that best works for them. This will provide self-service opportunities where they currently do not exist, as the current process requires the customer to call to request and schedule this work.

The Service Tracker Project will expand an emerging service tracking application into short-cycle electric service work types. The application will provide customers with improved communications following a utility service request, including the ability to track the Company's response. In 2018, the Company received over 140,000 requests from customers requesting utility work. Recognizing the need to provide customers frequent status updates regarding these requests, the Company is pursuing development of a service application that will allow customers to not only request service or report emergency needs, but also provide customers with safety information and instructions on what to do next. In addition, customers will see which crew will be responding, when they will arrive, and important contact information. The tracker will be hosted on the Company's website and will be mobile responsive, also allowing for customers to receive updates via text and email. Likewise, the crew will receive immediate notes on what the customer reported and how to contact the customer if needed. This application will reinforce safety messages, improve customer confidence, and reduce follow-up calls to the contact center.

The Streetlights initiative reflects a commitment to transformational changes on how the Company manages streetlight services, including modification of organizational structure, processes, business rules, and use of technology to better meet and exceed stakeholder expectations. In late 2019, the Company established a dedicated Streetlight Product Owner role to lead these efforts and developed a new Streetlight Application that will consist of a web-based streetlight outage reporting tool with restoration notifications, much like those provided today for electric service outages, for customers who report outages and for affected municipalities. Operationally, the tool will use streetlight databases to help improve reporting accuracy and provide specification data that will expedite restoration, reduce duplicative work stemming from multiple outage reports, and reduce delays caused by lack of information. The database will also reduce confusion that often occurs in the process of determining streetlight ownership, and subsequent service responsibility, by identifying whether service responsibility is that of the Company or a municipality. Using this tool, the Company will be better able to prioritize the restoration of streetlight outages and understand customer impact. This new application will also allow gathering of customer insights and data analysis to gain reliable data on outage restoration times, geographic outage patterns, equipment lifespans, and similar information that will help design and prioritize further improvements.

In 2019, the Company sent over 30 million alerts to customers containing outage information (such as outage cause and ETR updates) and Billing and Payment information (including billing statement availability, payment reminders, and usage alerts). The Alert Upgrades will continue to improve this service by implementing a version upgrade to the platform used to manage customer alerts. This new platform will provide new features, including:

- The ability to update alert messages in real-time rather than relying on the vendor, and the ability to quickly and easily test different versions of messaging with customers; and
- Natural language processing and machine learning to allow the system more flexibility in processing more than a few keywords. Currently, 33% of inbound text messages from our customers fail because they contain something other than a keyword. This enhanced ability would create a more seamless customer experience and decrease the number of manual interventions and calls.

These upgrades will also allow the Company to introduce new past-due (dunning) billing status notifications using the existing platform. In 2018, the Company sent over 1.6 million disconnect notices and received 205,000 calls related to these notices. Currently, dunning and associated payment status is only available by calling a live agent during business hours, which often creates hardship and a barrier for customers who are experiencing difficulty.

Q. Please describe the promotion of self-services.

A. Although more and more customers are accustomed to using the internet to buy merchandise or pay bills online, many customers are still not familiar with the online self-service features offered by the Company. The Company has identified services that have great potential for improvement in digital participation, which are expected to improve customer satisfaction and reduce costs.

The first digital growth opportunity is when customers are moving. Customers initiate over 900,000 moving-related interactions with the Company on an annual basis, with only one-third successfully completed online. Reasons for this limited self-service completion rate fall into two categories. The first category is simply technology related. There are many customer-use cases (such as a pending balance or an overlap in moving dates) that self-service functionality does not yet address, thus requiring the customer to call an agent during business hours. Improvements to a few of these conditions during 2019 resulted in a 10% increase in online self-service completions. Company witness Tolonen sponsors the $2,568,641 in capital and $221,188 in O&M for two separate projects to complete the changes necessary to improve the technology-related issues to increase self-service completion rates for moving-related interactions. These are discussed in greater detail in Exhibit A-76 (SQM-3). The second category is customer behavior. Many title companies and real estate agents specifically tell their customers to call Consumers

Energy (and other utilities) to update their service. Thus, a key component to increasing online self-service is a communications and educational effort for these companies about convenient online self-service options that are available to Consumers Energy customers. In addition, there is publicly available moving information that can be used effectively to address these customers directly. The Company is seeking to test and implement a communications campaign to educate those who are moving, and those companies that have significant influence on customers who are moving, to help increase self-service adoption. Communications and data testing will provide reliable insights into how to maximize the effectiveness of these communications at increasing self-service adoption, reducing phone calls, and ultimately delivering a better moving experience.

Q. When does the Company expect to see the cost savings from implementing and promoting its self-services?

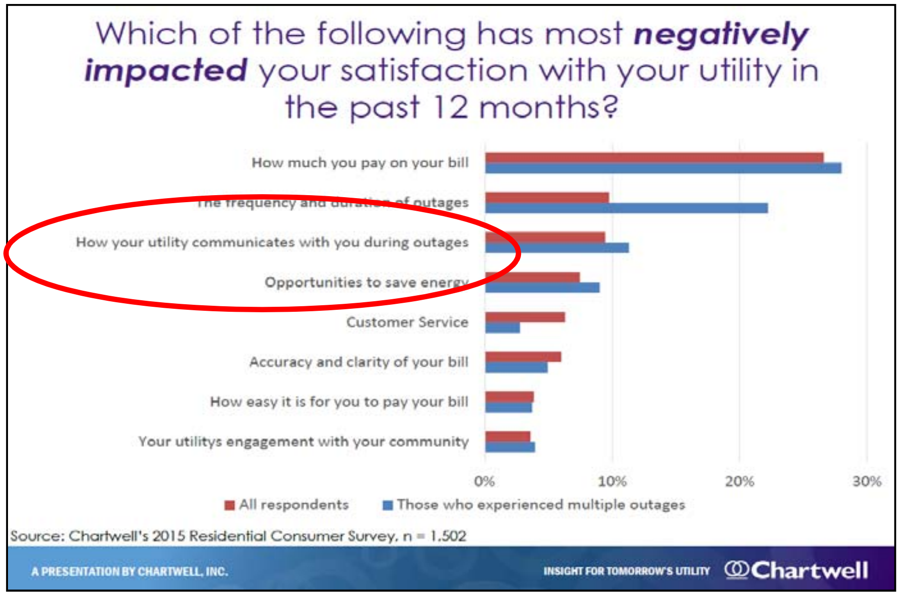
A. At this time the Company projects to see modest cost savings beginning in 2021. Over the coming years, however, the Company is expecting much greater savings as it increases the number of customers taking advantage of electronic billing by 5% per year and reduces the number of customer calls to a call center representative by 7% per year, which is expected to translate into approximately $200,000 per year in savings.

Q. Please describe the Outage Experience Improvements.

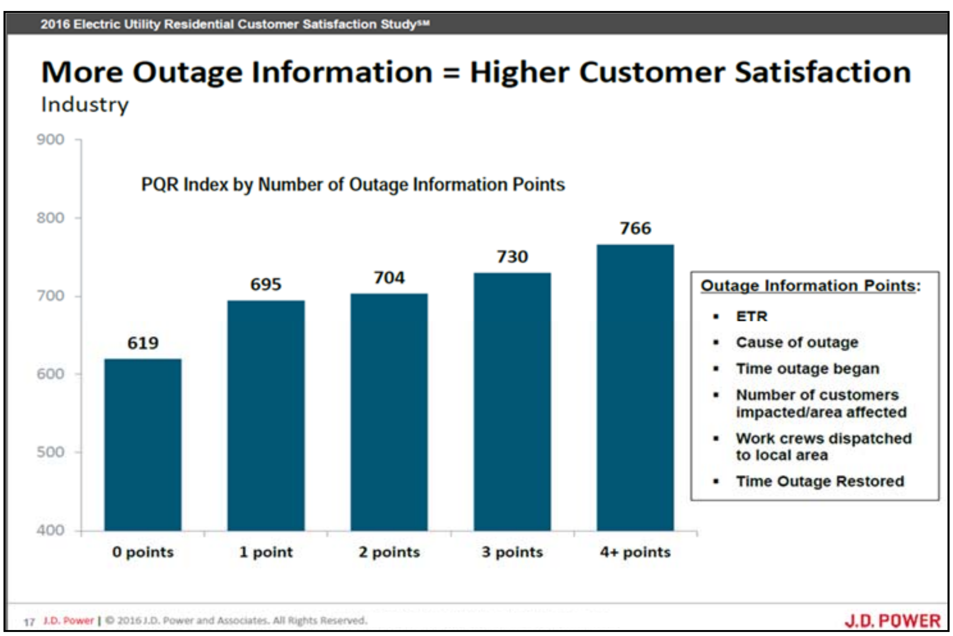
A. The Company has identified a number of promising opportunities to improve customers' experience when their electric service is interrupted, including storm activation events to provide needed supplies during outages in extreme weather situations, improvements to ETR practices to better meet customer expectations and need for information, and communications to affected customers before, during, and after significant weather events.

As shown in Figures 11a and 11b below, outage information is important to customers and their satisfaction with their utility.

<u>Figure 11a: Chartwell data shows that outages account for 2 of the top 3 reasons for negative influence on customer satisfaction.</u>



<u>Figure 11b: JDPower data shows that more information during an outage results in a better experience.</u>



The Company's Customer Research team also conducted customer surveys following the 2019 July and October storm events. The results further corroborated the need to provide customers timely and accurate information. During the October event, customers recalling receiving information prior to, during, and after the outage resulted in a CXi score of 81 (of a possible 100) versus customers who recalled none resulting in a score of 24. Also, customers who received an ETR within 10 minutes of the outage had greatly increased satisfaction, with a score of 99.

Q. Is the Company projecting any test year IT project funding related to the Customer Experience Design work described above?

A. Yes. Company witness Tolonen is sponsoring test year IT costs that include $9,114,701 of capital and $1,568,428 of O&M expenses for IT projects that support the Customer Experience Design work. Collectively these IT projects are related to updates to comply with regulatory billing changes, improve billing functionality, and improve customer satisfaction. These projects also improve the self-service relocation technical issues briefly discussed above. I have briefly described each of these IT projects, and provided the corresponding expenses, in Table 3 below. A more complete description of each project is provided as part of Exhibit A-76 (SQM-3).

Table 3 – Customer Experience Design IT Projects
($ in Dollars)

IT Project	Description	Expenses	
		Capital	**O&M**
A. Bill Design and Delivery Transformation	The Bill Design and Delivery Transformation project will execute a bill redesign for all rates and program combinations, including necessary software replacements and a flexible print and delivery outsourcing initiative.	$5,209,551	$926,970
B. Move In/Move Out Digital Redesign	This Move In-Move Out project will allow Move In and Move Out web pages to be better supported on mobile devices.	$1,105,813	$46,215
C. Business Customer Interval Web Portal	The Business Customer Interval Web Portal project will develop a new Interval Web Platform (IWP) for Business Customers to provide the customers insight into their energy usage.	$0	$165,000
D. On-Bill Financing Project	The On-Bill Financing Project will enable product purchases by customers utilizing on-bill financing.	$1,336,508	$138,270
E. Summer Peak Use Rate ("SPUR")	This project will continue the implementation of TOU rates for Net Metered and PayGo customers.	$0	$116,000

F. Move In Move Out 3.0	The Move In Move Out Version ("MIMO") 3.0 effort will update and re-design the customer experience to remove barriers and increase ease for customers who desire self-service in the MIMO experience.	$1,462,828	$175,973
Total		**$**9,114,701	**$** 1,568,428

III. <u>CUSTOMER INTERACTIONS</u>

Q. Please provide an overview of Customer Interactions.

A. Customer Interactions is responsible for using the research, analytics, and customer experience design work described above to interact with the Company's customers through the various channels (such as digital, phone, mail) customers choose. This work includes the following five main areas of focus: (i) Digital Customer Experience; (ii) Customer Contact Center; (iii) Business Customer Care; (iv) Field Payment Channels and Claims; and (v) Credit and Assistance. To effectively perform in these five areas, the Company is projecting $25.7 million of O&M expenses for the test year ending December 2021. As shown on Exhibit A-75 (SQM-2), page 3, this represents a decrease in O&M expenses of $3.5 million from the $29.2 million expended in 2018. The Company is also projecting $0.02 million of capital for a project that will automate address changes for customers, eliminating 8,000 manual address changes annually. The capital is included on Exhibit A-12 (SQM-1), Schedule B-5.5.

A. Digital Customer Experience

Q. Please provide an overview of Digital Customer Experience ("DCE").

A. DCE is responsible for the operation and continuous improvement of the Company's customer-facing digital applications, including the website and self-service functionality. Operationally, the DCE team collects over 3,000 points of customer feedback every month, which drives the team's priorities in three simultaneous work cycles: (i) website changes the team can make itself using available configuration tools; (ii) managing the solution design, development, and launch of monthly releases to add new features or modify website user flows; and (iii) leading major technology projects that add new functionality or modify business rules to better serve customers. In addition, this team is also responsible for managing the Company's online account management and self-service capabilities, website analytics, two-way alert communications, mobile device usability, and website content development.

Q. What types of transactions do customers complete on the digital channel?

A. The most common reasons customers use the Company's website is to check the billing status of their account, make a payment, report an outage, view the expected restoration status of an outage, view energy usage information, and view additional service information – such as auto-pay, eBill enrollment, budget billing, or Energy Waste Reduction rebates. In January through June 2019, the website averaged over 170,000 web transactions per month, a 51% increase from 2018.

Q. How successful are online services for customers?

A. Of the 27 million website sessions in 2018, the Company received customer feedback that 80% of the time (21 million web sessions in 2018) customers can accomplish their goal online. The other 20% of the time (6 million sessions in 2018) customers cannot accomplish their goal online, primarily due to missing information or technology limitations or failures. In addition, 18% of customers who call the Company indicate they tried to address their question online before calling. By investing in its digital applications, the Company plans to address these gaps, thereby reducing the future number of calls received, lowering transaction costs, and improving customer experience.

Q. Please explain why the Company is continuing to invest in the digital channel.

A. Continued investments are needed to keep pace with changes in customer habits and expectations as they continue trending toward more integrated and sophisticated digital services. For instance, approximately 89% of United States adults are using the Internet, 77% have access to Internet-enabled mobile devices, and 57% are using their devices for online banking transactions. In addition, survey results from Accenture's 2016 New Energy Consumer Research indicate that:

- 92% of consumers would be more satisfied if their energy provider could personalize their overall customer experience;
- Digitally engaged consumers are more satisfied with their energy provider (77% vs 64%) and are more likely to trust their provider on advice regarding energy optimization and data protection;
- 89% believe it is important to have a seamless customer experience with their energy provider across all digital and non-digital channels. 83% report it would negatively impact satisfaction if the energy provider was unable to deliver such, and 77% would be discouraged from signing up for additional products and services; and
- Forrester Research reports that 79% of customers prefer self-service over traditional channels such as phone and email.

More and more customers are choosing to conduct business online – such as banking, paying bills, and making purchases. Between 2016 and year-end 2018, the Company experienced a 79% annual increase in website sessions and a 69% increase in the number of unique users per month. Further, the Company supported more than 27 million website sessions through 2018 and sent more than 9 million phone, email, and text alerts to customers. The projected investments in this case will assist the Company with (i) addressing performance gaps and (ii) keeping pace with the changes in how customers prefer to interact with the Company.

Moreover, the Company expects these investments to improve customer satisfaction and ultimately reduce costs through lower on-line transaction costs of $0.11 versus agent-assisted costs of $8.78 per live agent call.

Q. Is the Company projecting any test year IT project costs related to the DCE?

A. Yes. Company witness Tolonen is sponsoring test year IT costs that include $6,114,268 of capital and $714,450 of O&M expenses for four IT projects that support the DCE work described above. Collectively these IT projects will improve the Company's ability to serve customers within the channel of their choice, namely, the mobile channel, and improve the experience of customers in completing self-service transactions within that channel. Although the purpose of these investments is primarily related to increases in digital tool functionality in response to customer feedback, the Company projects roughly $0.7 million in future O&M expense savings related to operational efficiency beginning in 2022. These IT projects are briefly described, with the corresponding expenses, in Table 4 below. A more complete description of each project is provided as part of Exhibit A-76 (SQM-3).

Table 4 – Digital Customer Experience IT Projects
($ in Dollars)

IT Project	Description	Expenses	
		Capital	**O&M**
A. Dashboard Redesign	The current online dashboard is not structured to provide customers the information they need immediately upon logging in at a glance. Observed user behavior indicates that customers struggle with the dashboard load time and locating information that is meaningful to them. This redesign will improve that process.	$2,528,027	$164,670
B. Website Redesign	In order to deliver an effective customer experience and service customers more robustly within the mobile channel, Consumers Energy's mobile website needs to be optimized to improve customer experiences in outage, billing and payment, and move in/move out.	$3,184,331	$434,445
C. Cross-Channel Analytics	Improved ability to understand and address customer pain points in self-service processes through use of enhanced speech analytics and customer experience tools.	$0	$79,200
D. Data Lake Entry	Migrating all Customer Operations data to the data lake will save costs by reducing now manual efforts to collect, consolidate, and analyze data.	$401,911	$36,135
Total		**$6,114,268**	**$714,450**

B. 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 2018, call center representatives answered 4.2 million customer calls, a decrease of nearly 400,000 calls from the previous year. Likewise, the Interactive Voice Response ("IVR") system addressed 8.5 million calls during 2018. To continue this work the Company is projecting $14.5 million of O&M expenses for the test year ending December 2021. As shown on

Exhibit A-75 (SQM-2), page 3, this represents a decrease in O&M expenses of $1 million from the $15.5 million expended in 2018. This decrease in operating expense has been achieved through reducing call defects, while striving to maintain the Company's Average Speed of Answer ("ASA") at 66 seconds during the test year and to deliver the quality that our customers experience when they contact the Company via the Customer Contact Center.

Q. Please explain why the Company is planning to maintain the ASA at 66 seconds.

A. The Company is committed to an excellent customer experience across all its service channels. Recognizing that customers would prefer spending their time doing something other than waiting for a call center representative, the Company is planning to maintain its internal and external resources in the call center at current staffing levels and to maintain its ASA at 66 seconds.

Q. Is the Company projecting any test year IT project costs to support the work proposed by the Customer Contact Center?

A. Yes. Company witness Tolonen is sponsoring test year IT costs that include $2,260,918 of capital and $157,030 of O&M expenses for the Voxai Survey Tool and the Landlord Small Business Portal IT projects presented in the table below. The Voxai Survey Tool project will implement an immediate post-interaction customer survey tool to allow real-time feedback and data regarding the customer's experience with the Company's IVR or live contact center. Currently, a third-party vendor is utilized to perform surveys via a live agent two days post-interaction. Engaging a real-time survey tool to gather feedback from customers will not only improve the timing and accuracy of data, but will also improve the cost for generating this critical feedback. The Landlord Small Business Portal project will modernize the existing Portal to reflect current usability standards and allow for increased adoption of digital services by landlords and management companies. Table 5 provides a summary of these projects and more complete descriptions are provided as part of Exhibit A-76 (SQM-3).

Table 5 – Customer Contact Center IT Projects
($ in Dollars)

IT Project	Description	Expenses	
		Capital	**O&M**
A. Voxai Survey Tool	Provides for real time surveys and data collection from higher volumes of customers to drive better feedback and faster resolution of customer concerns.	$166,272	$7,920
B. Landlord Small Business Portal	Modernizing the Landlord portal will increase adoption and utilization of digital services by landlords and management companies thus reducing cost through reduction in contact center support and resources.	$2,094,646	$149,110
Total		$2,260,918	$157,030

C. Business Customer Care

Q. Please provide an overview of Business Customer Care.

A. Business Customer Care ("BCC") works directly with the Company's commercial and industrial customers. The organization's main goal is to deliver an exceptional one-to-one experience, while identifying opportunities that add energy value for business customers. Overall, the BCC serves 116,000 customers, which equates to 216,000 contract accounts. This represents $2.6 billion in revenue, which is approximately 46% of the Company's total annual revenue.

This department is comprised of the Business Center, which includes phone agents, and account management, which is responsible for assisting the Company's larger business customers. To continue the work in this area, the Company is projecting $2.8 million of O&M expenses for the test year ending December 2021. As shown on Exhibit A-75 (SQM-2), page 3, this represents a decrease in O&M expenses of $0.3 million from the $3.1 million expended in 2018.

Q. Is the Company projecting any test year IT project costs to support the BCC proposals in this proceeding?

A. Yes. Company witness Tolonen is sponsoring test year IT costs that include $115,500 of O&M expenses for the Large Customer Rate Tool IT project that supports the BCC work described above. This project will improve the Company's rate design functionality and the Company's response to business customer rate information requests. This project will provide value to both the Company and its customers by: (i) automating the intensive, manual processes that account managers utilize in working with large businesses to ensure they are on the best possible rate; and (ii) improving functionality to better assist large business customers with evaluating different rate options. A more complete description of this project is provided as part of Exhibit A-76 (SQM-3).

D. <u>Field Payment Channels and Claims</u>

Q. Please provide an overview of Field Payment Channels and Claims.

A. Field Payment Channels and Claims is responsible for operating the Company's 14 Direct Payment Offices, investigating theft, and resolving claims of damage to Company and customer property. Twelve of the 14 payment offices are located within existing Company facilities, making them a cost-effective option for customers to pay their bills in person. Without these options, customers that do not have electronic means of paying their bill, i.e. credit card or bank accounts, would be forced to utilize third-party agencies to pay their utility bill, incurring a service charge in addition to their energy bill. In 2018, the payment offices served 1,007,415 customers and collected $212,400,000 in electric, natural gas, and combination customer payments. These offices serve some of the Company's most vulnerable customers, such as seniors and low-income customers, providing them with a community resource that can connect them with billing options and assistance opportunities. This is a payment channel that customers continue to choose, especially within these vulnerable customer segments.

The Damage Claims and Loss area investigates and resolves incidents where damage was caused either to the Company's or a customer's property. In 2018, this area resolved 911 claims of damage to customer property in the amount of $1.1 million and recovered $1 million in damages caused to the Company's property by others. To continue this work, the Company projects $1.9 million of O&M expenses for the test year ending December 2021. As shown on Exhibit A-75 (SQM-2), page 3, this represents a decrease in O&M expenses of $0.3 million from the $2.2 million expended in 2018.

The theft investigation team provides a critical service of investigating and finding energy theft within the Company's communities. Stopping this theft is important both for maintaining the safety and integrity of the Company's system and keeping costs lower for customers. In 2018, the theft team created a theft analytics tool that enables them to utilize millions of pieces of customer information to create use cases that can help to identify instances of theft in the community. The team is continuing to expand the uses and workings of the tool to include more data to help refine those use cases, as well as create a tool that will help identify theft on the commercial side of the business.

Q. Is the Company projecting any test year IT project costs to support the Field Payment Channels and Claims proposals in this proceeding?

A. Yes, Company witness Tolonen is sponsoring test year IT costs that include $311,842 of capital and $131,784 of O&M expenses for the Commercial Theft project. This project will allow the Company to more effectively identify and reduce theft by Commercial customers through the use of smart meter data and algorithms. A more complete description of the project is provided as part of Exhibit A-76 (SQM-3).

E. <u>Credit and Assistance</u>

Q. Please provide an overview of Credit and Assistance.

A. Credit and Assistance addresses customer accounts that are past due or involved in bankruptcy. Employees within this area manage the collections cycle, beginning with issuing a notice to customers through visiting their premises to disconnect service. Additionally, this group manages contracts with outside collection agencies to recover payments from customers with outstanding balances. In 2018, the Company recovered $17.8 million of previously written off customer balances. Recovery of these payments directly offset the uncollectible expense discussed in the testimony of Company witness Karen M. Gaston.

This team is also responsible for administering the Company's Consumers Affordable Resource for Energy ("CARE") program, which supports low-income customers who are struggling to pay their monthly energy bills. By coordinating with other organizations, this program has obtained $18.3 million of assistance requested through the Michigan Energy Assistance Program ("MEAP"). Furthermore, this program has helped prevent customers from being disconnected by working with agencies across Michigan to ensure both state and federal assistance is correctly applied to customer accounts. In 2018, the CARE program was able to secure $35.5 million in assistance on behalf of the Company's most vulnerable customers. To continue these efforts, the Company is projecting $3.3 million in O&M expenses for the test year ending December 2021. As shown on Exhibit A-75 (SQM-2), page 3, this request represents an increase in expenses of $1.1 million from the $2.2 million expended in the 2018 historical year. This increase is due to a rise in payments to third-party agencies that perform collection activities on the Company's behalf. These activities are necessary to control uncollectible expenses and limit the impact on other customers.

Q. Is the Company proposing a new income assistance provision to support low-income customers?

A. Yes, the Company is proposing a new Low Income Assistance Credit ("LIAC") provision substantially similar to the LIAC for natural gas customers originally approved in Case No. U-18124.

Q. Is the Company proposing to alter the current Residential Income Assistance ("RIA") credit?

A. No. The Company is proposing to maintain the current RIA. The current RIA credit provides qualifying low-income electric customers with a monthly credit which equates to the amount of the monthly residential electric customer charge. In addition to the RIA, the

Company is proposing to create a more substantial LIAC to target approximately 4,200 of the Company's most vulnerable customers.

Q. Why is the Company proposing the LIAC?

A. Utilizing the Company's CARE program experience as a model, the Company is proposing a LIAC Provision to provide meaningful long-term assistance to eligible low-income customers that are struggling to pay their utility bill. As observed through past and current low-income programs, proactive solutions involve providing vulnerable customers with assistance that is timely and sustained within a long-term payment plan model. This approach mitigates the reoccurrence of crisis situations. With aid that is meaningful and predictable, customers who may otherwise experience a crisis are able to make necessary payments, stabilize their household budget, and support self-sufficiency goals. This means of assistance, in turn, results in a positive customer interaction and overall experience. Moreover, the innovative LIAC solution as a low-income customer support program provides wider impact. This is expected to result in efficiencies in the collection cycle, thereby enabling Consumers Energy to better manage its arrears and uncollectible expense.

Q. What is the amount of the credit that Consumers Energy is proposing for the LIAC Provision?

A. The Company is proposing that the LIAC Provision provide low-income customers with a $30.00 per month credit on their electric bill, not to exceed the total electric monthly bill amount.

Q. Why does the Company believe that $30.00 a month is an appropriate level of assistance?

A. The proposed monthly credit provided through the LIAC Provision is expected to effectively and proactively assist customers in managing their electric bills and, in turn, help prevent crisis situations and service disconnections, especially when coupled with long-term assistance programs. Moreover, an affordable bill will support improved payment patterns that will assist with customers' long-term self-sufficiency goals.

Q. Is the Company proposing to offer any alternative programs for low-income customers that request assistance after the LIAC Provision credit participation cap is met?

A. Yes. As available, the Company will provide alternative assistance options to qualified customers who are not able to participate in the LIAC or RIA provisions. These programs include the CARE Program, the Shut-Off Protection Plan, the Winter Protection Plan, Pre-pay, the Helping Neighbors Program, as well as referrals to state and non-profit agency assistance through 2-1-1, the Department of Health and Human Services, and the Michigan Home Heating Credit.

Q. How does this work for the Company's combination gas and electric customers?

A. Combination customers are eligible to receive both electric and gas credits.

Q. Please explain how the Company's proposed LIAC Provision will be implemented in relation to other low-income customer assistance programs.

A. The proposed LIAC Provision will be implemented in conjunction with the other utility assistance programs, agency assistance programs, and government assistance programs. The Company intends to use these existing programs to identify customers that can utilize the assistance provided by the LIAC Provision. Together, these programs provide opportunities to assist low-income customers with customized solutions depending upon their type of need and time of year.

Q. Why is the proposed LIAC Provision necessary when customers can already receive the RIA Provision?

A. The proposed LIAC Provision aligns with MEAP requirements which seek to promote and support a self-sufficiency journey for low-income customers by providing meaningful, longer-term assistance. The proposed LIAC Provision allows for effective use of available funding sources. In addition, the proposed LIAC Provision will provide an opportunity for the Company to continue gathering insights through comparative analysis and identify best practices available to serve low-income customers.

Q. What is the basis for targeting a smaller group of low-income customers with a more substantial assistance?

A. Longer-term payment programs benefit customers who wish to engage in solutions and begin a journey to self-sufficient account management. As a result, the value of the assistance is demonstrated to these customers, and the program incentivizes ownership of responsibility and accountability to successful outcomes. This evolution is demonstrated best within the Company's CARE Program, funded by MEAP. Since its 2013 inception, CARE's delivery model has demonstrated exceptional success in changing low-income customers' payment behavior. Similar to the Company's LIAC Provision proposal in this case, the goal of Consumers Energy's CARE Program is to encourage and support good payment habits and reduce consumption. In 2019, the CARE Program encouraged more than 20,000 participants to reduce their arrears over time and adopt the habit of making regular payments with the goal of self-sufficiency to afford the energy they consume. Like CARE, the proposed LIAC Provision is expected to enable more affordable energy to customers who would otherwise remain in a cycle of need and create a positive customer experience. The necessary rate adjustments for both the RIA and LIAC are further explained by Company witness Hubert W. Miller.

IV. Billing and Payment

Q. Please provide an overview of Billing and Payment.

A. Billing and Payment is responsible for using customer feedback collected as part of the analytics research and various interactions to ensure: (i) customer payment processes are consistent and simple; (ii) monthly energy bills are accurate and easy to comprehend; and (iii) customers receive their bills in a timely fashion. The work in this area primarily falls into the following three areas: (i) Customer Payment Program; (ii) Customer Billing; and (iii) Business Support. To effectively perform in these three areas the Company is projection $22.8 million of O&M expenses for the test year ending December 2021. As shown on Exhibit A-75 (SQM-2), page 4, this represents an increase in O&M expenses of $3.5 million from the $19.3 million expended in 2018.

A. Customer Payment Program

Q. Please describe the Customer Payment Strategy.

A. Customer Payments are among the most sensitive and frequent touchpoints the Company has with customers, with approximately 33 million payments made annually. In 2014, the Company initiated a Customer Payment Strategy that 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.

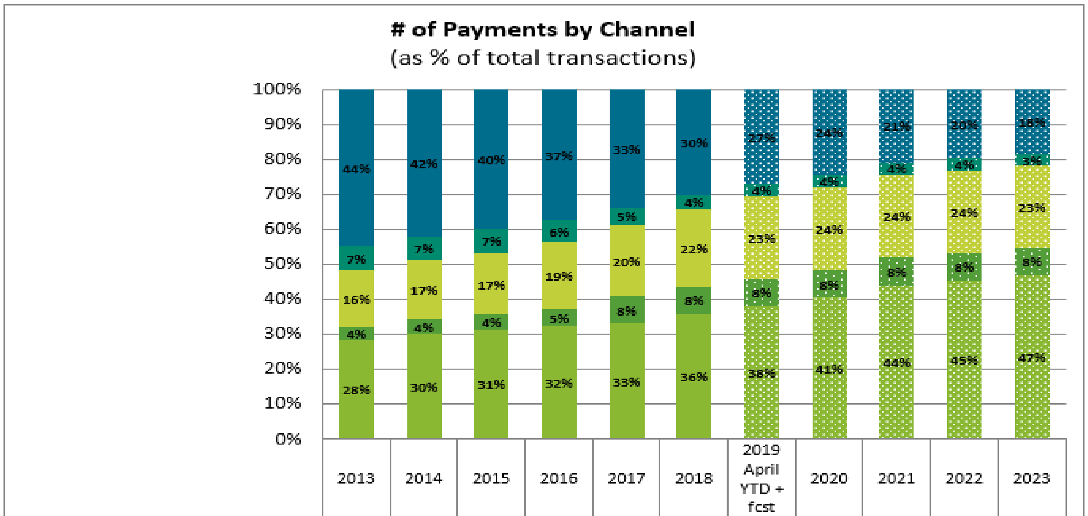
This has resulted in a significant improvement in customer satisfaction and reduction of payment-related calls and complaints. The Company continues to make it a priority to accommodate customer preferences with simple and consistent payment options.

Operating costs of customer payments continue to evolve with changes in customer behaviors. As such, the Company is projecting \$10.35 million in test year O&M expenses shown on Exhibit A-75 (SQM-2), page 4. This represents a \$3.2 million increase from the \$7.2 million expended in 2018. The increased expense is attributed to: (i) the continued increase in customer use of credit cards to make a payment; and (ii) several projects to improve customer payment options which are discussed in greater detail later in this section of my testimony. Figures 12a through 12c show the trends and forecasts for customer payment behaviors showing increasing credit card payments and the associated costs to the Company for customer payments.

Q. Have customer payment behaviors changed in recent years?

A. Yes. As illustrated in Figure 12a below, the biggest change in payment behavior is the shift away from mail to electronic payments. From 2013, payments by mail have fallen from 44% to 30% of total payments in 2018, while electronic payments have increased from 28% to 36% for the same period. The Company expects the trend of increasing electronic payments to continue into the foreseeable future with credit cards as the main driver. The below figure illustrates the growth of electronic payment methods, including credit cards, over time.

Figure 12a – Historical and Forecasted Customer Payment Mix

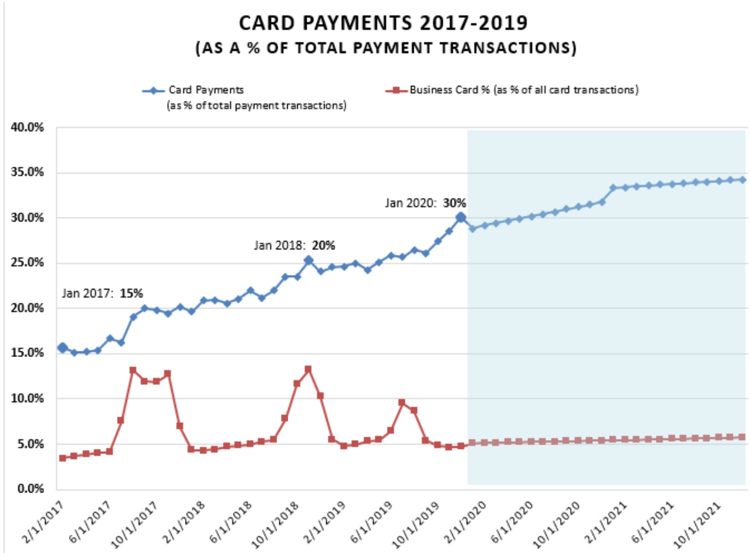


	2013	2014	2015	2016	2017	2018	2019 April YTD + fcst	2020	2021	2022	2023
Mail	44%	42%	40%	37%	33%	30%	27%	24%	21%	20%	18%
In Person (CE Offices & APS)	7%	7%	7%	6%	5%	4%	4%	4%	4%	4%	3%
Auto-Pay (RCP & Auto ACH)	16%	17%	17%	19%	20%	22%	23%	24%	24%	24%	23%
Phone	4%	4%	4%	5%	8%	8%	8%	8%	8%	8%	8%
Electronic (Online & Web Banking)	28%	30%	31%	32%	33%	36%	38%	41%	44%	45%	47%

Q. Has the Company seen a corresponding increase in credit card payments?

A. Yes. Following the Company's decision to remove credit card payment fees in January of 2017 there has been a steady rise in credit card usage. As illustrated in Figure 12b below, use of credit cards as a percent of total transactions has increased from 15% in January of 2017 to approximately 24% in 2018. Credit card use accounted for 30% of customer payments (residential and business) at the end of 2019.

Figure 12b – Projected Increase in Customer Card Payments



Q. How have the increasing credit card payments impacted customer payment program expenses?

A. As illustrated in Figure 12c below, the total O&M expense related to credit card payments has steadily increased as the number of payments has increased. In 2018, the expense was $6.3 million and the Company expects it to grow to $7.0 million in 2020.

Figure 12c - Illustrates 2017-2020 (forecasted) credit card payment activity and costs

Description	2017	2018	2019	2020
Credit Card Payments	5.2M	7.2M	8M	9.2M
Credit Card Payment % of Total	20.2%	24.1%	26.1%	28.5%
Total Cost of Credit Card Payments	$4.5M	$6.3M	$6.6M	$7.0M

Q. Is the Company projecting additional funding in this case to support the proposed work in the test year for Customer Payment Program projects?

A. Yes. The Company is undertaking several projects listed in the below Table that continue the evolution of payment options necessary to keep pace with changing customer expectations and realization of payment-related business objectives. They will provide the flexible options that customers expect, continue to drive use of electronic billing, and eliminate utility payment fees that create confusion and frustration, especially among our most vulnerable customers.

Table 6 – Customer Experience & Communication Projects

Project	Description	O&M	Capital
Secure PDF	This project will add a new ebill delivery and payment option known as Secure PDF.	$30,000	$1,020,000
Authorized Pay Station Fee Removal	This will remove the last remaining customer payment fee, which is $1.75 for use of third party payment centers.	$1,913,000	$0
Payment Extension	Language modifications to online and IVR user flows will make the payment "grace period" more apparent and value-add to customers with good payment histories. This is expected to improve customer understanding regarding the Company's payment terms.	$15,000	$51,000

In Person Network Expansion	This expands the network of third-party locations customers have available to pay a bill statewide. This provides customers with more flexible payment choices, especially in rural areas.	$30,000	$128,000
Total		**$1,988,000**	**$1,199,000**

Q. Please describe the Customer Payment Program projects.

A. As the largest and most frequent touch point with customers at over 32 million customer payments made annually, the Company recognizes the significance that continued improvements and simplifications to payment processes can have for customers. These projects have been selected to keep pace with changing customer expectations and to help achieve payment-related business objectives:

- **Secure PDF:** This project encompasses the design and launch of an all-new electronic billing and payment option that allows customers to pay a bill directly from a .pdf attachment in a Company email. The customer can view the bill and receive any relevant messages from the Company, but save time by avoiding the need to log into a Company or bank website. Secure PDF is especially appealing to large business customers with consolidated accounts who must log in to each using unique authentication to pay their bills. While the Company has made great strides at improving ebill participation from 34% in 2018 to 36% in 2019, secure PDF is recognized to be a necessary addition for the Company to achieve or exceed the target of 40%.

- **Payment Extension:** It is unnecessary for customers who are in good standing and have consistently made on-time payments to be communicated with in a fashion that implies otherwise. As such, the Company would like to change the "one size fits all" messages to customers who are late on a payment. Call Center agents frequently make use of the Company's five-day grace period to accommodate customer requests or concerns about on-time payments, but this messaging is absent from the IVR and website. Making these changes is expected to improve important customer perceptions of "time to pay" and overall perception of friendly payment options. It is also expected to help reduce unnecessary phone contacts associated with this topic.
- **In-Person Network Expansion:** The existing in-person payment network consists of 430 agents that process 600,000 payments annually including Wal-Mart, Kroger, and K-Mart. Over 100 K-Mart locations have closed in recent years leaving only 12 total walk-in pay stations in rural communities in northern Michigan north of Saginaw. The Company is proposing to expand its network of retail establishments that can accept customer payments. The proposed expansion adds 1,850 new agents including 7-11, Dollar General, CVS, and Speedway that offer expanded hours of service and vast demographic coverage. Customers would pay with a unique barcode that contains account information which differs from existing pay agent structure. Addition of the "In-Lane" channel would increase walk in agents north of Saginaw by 90%. A pilot is proposed in the northern region to gauge customer feedback and feasibility of expanded network and barcode presentment.

The Company is also proposing to no longer pass along to customers the $1.75 service charge for making a payment at third-party establishments, which are often the most convenient payment options for our rural customers. This easily implemented change aligns with no-fee credit card payments and positions the Company to promote unilateral "no fee" payments at any time. Beyond the additional convenience and consistency this creates, it is an important strategic evolution of the Company's payment strategy for two reasons: (i) billing consolidators that many customers use (knowingly or not) can be very expensive to use and have potential to be confused as payment fees imposed by the Company; and (ii) utility scams that threaten power shut-off and immediate payments continue to hit residential and business customers alike. Removing fees – and promoting that Consumers Energy does not charge fees to pay and will never demand an immediate payment to avoid being shut off - is a positive message that can help build reputational credibility and heighten awareness that requirements such as these are not associated with the Company and are not authentic.

B. <u>Customer Billing</u>

Q. Please provide an overview of Customer Billing.

A. Customer Billing manages the "exceptions" process, which is a quality control process designed to review unusual bills (digital and paper) before they are sent to customers. As part of the exceptions process, this area may contact customers to gather additional information or to inform them of a potential billing issue, correct the bill through a billing adjustment process, or re-read the meter as part of a validation process. Through rigorous continuous improvement efforts to provide an accurate bill every time to customers, the Customer Billing team has continued to optimize their processes and technology to aid in the review of billing exceptions. In 2018, Customer Billing saw a 30% reduction in the number of inaccurate bills, from approximately 344,000 in 2017 to approximately 240,000 in 2018. Ensuring that customers receive the right bill every time is critical. To continue this work, the Company is projecting \$3.6 million of O&M expenses for the test year ending December 2021. As shown on Exhibit A-75 (SQM-2), page 4, this represents an inflation increase in O&M expenses of \$0.6 million from the \$3.0 million expended in 2018.

C. <u>Business Support</u>

Q. Please provide an overview of Business Support

A. Business Support is responsible for stationery, forms, and postage related to the Company's billing and dunning processes along with other support related activities. In 2019, the Company mailed over 23 million paper bills and over 3 million dunning notices to customers. As illustrated in Figure 13, the number of customer bills mailed has declined by 2.9 million during 2019 as a result of deliberate efforts to increase electronic billing participation. This savings has been offset by an increase for additional dunning notices mailed during the year in an effort to reduce past-due balances. The Company is projecting \$8.8 million of O&M expenses for the test year ending December 2021 to continue supporting expenses associated with billing, dunning communications, and support services. As shown on Exhibit A-75 (SQM-2), page 4, this represents a \$0.3 million decrease of O&M expenses from the amount expended in 2018.

Figure 13

	2018	2019	2020 projected	2021 projected
# Customer Bills	26.5M	23.6M	24.2M	23.6M
# Dunning Notices	2.7M	3.3M	3.5M	4.0M
O&M Expense	$9.1M	$8.48M	$8.78M	$8.82M

V. DEMAND RESPONSE PROGRAMS

Q. Please explain the DR programs offered by the Company.

A. The Company offers a DR portfolio comprising both residential and business DR programs. Projected O&M costs for the test year for these programs are $34.7 million and are included on Exhibit A-75 (SQM-2). Capital costs for these programs are projected to be $36.9 million from 2019 through the test year and are included in Exhibit A-12 (SQM-1), Schedule B5.5. 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.

Q. Please describe the regulatory framework for DR.

A. In its September 15, 2017 Order in Case No. U-18369, the Commission established a three-phase approach to addressing DR with capital costs approved in an Integrated Resource Plan ("IRP"), O&M costs reviewed and approved in the general rate case, and an annual reconciliation proceeding in which actual capital spending will be reconciled with the amount approved in the IRP and recovered through a general rate case and actual O&M spending will be reconciled with the amount approved and recovered through a general rate case. In June 2019, the Company received approval of its first IRP in Case No. U-20165. The Commission approved the Company's 2017 DR reconciliation in Case No. U-20164, and the 2018 DR reconciliation is pending in Case No. U-20563. The Company will file its 2019 DR reconciliation case at the end of May 2020.

Q. Is the Company proposing any changes to this framework?

A. While the Company is not proposing major changes to the DR regulatory framework, the Company is proposing to include a surcharge as part of the annual DR reconciliation process. The surcharge will allow for a customer refund in the event of an annual underspend, recovery of any prudent spending above that approved in rates, and collection of any future financial incentives for DR performance.

Q. How does the reconciliation process currently work?

A. Currently DR costs are recovered in base rates established in general rate cases. As part of the rate case process, the Company calculates a revenue requirement specific to DR-related capital investment and O&M expenses. This revenue requirement represents the DR costs that are included in base rates. During the DR reconciliation proceeding, actual DR costs for the applicable year are used to calculate an actual revenue requirement for the reconciliation period. This actual revenue requirement is compared to the DR revenue requirement used to set rates in the rate case or cases for the corresponding period of time. If the actual DR revenue requirement is higher than the revenue requirement used to calculate rates, the Company did not recover enough revenue and there is an under recovery. If the actual DR revenue requirement is lower than the revenue requirement used to calculate rates, the Company recovered more revenue than approved and there is an over recovery. The reconciliation proceeding establishes the over or under recovery, which under the current process will be held as either a regulatory liability or asset on the Company's balance sheet until a subsequent general rate case where it will be included in base rates.

Q. How are DR Performance Incentives handled under the current regulatory framework?

A. Under the current process, when the Commission approves a financial performance incentive in future reconciliation proceedings, the Company will carry a regulatory asset until a subsequent future general rate case proceeding where it will be included in base rates for recovery.

Q. Why is the Company proposing a surcharge for the reconciliation process?

A. Creating a surcharge will streamline and simplify the reconciliation process, eliminating potentially long lags for the recognition of overrecoveries and underrecoveries in rates. In addition, incorporating a surcharge in the reconciliation proceeding will allow the Company to recover any future performance incentive using the alternative revenue recognition approach described by Company witness Daniel L. Harry. For example, in the 2017 DR reconciliation in Case No. U-20164, the Company proposed and the Commission approved a $489,633 overcollection and regulatory liability. With no reconciliation surcharge, the Company will carry this liability until rates are set in the present case. With a projected 2021 test year, the Company will have held the overcollection for four years by the time it is recognized in rates. This is further complicated and extended by any potential amortization of the overcollection. With a reconciliation surcharge, the Company would be able to refund any potential over recovery or collect an under recovery immediately following the reconciliation proceeding. As to the performance incentive, ideally the Company would record the incentive in the same period that the DR expenses are incurred, presenting a better picture of the true economics of the program. This approach would be consistent with how the Company recovers performance incentives related to the EWR Program. As described by Company witness Harry, the Company is only allowed to record the incentive in the same period, under ASC 980-605-25, if a surcharge were in place to recover the incentive within a two-year period. In addition, if the performance incentive is recovered in base rates as part of a general rate case, there would be no mechanism in place to stop or alter the incentive recovery absent filing a new general rate case. But including the surcharge mechanism as part of the annual DR reconciliation proceeding provides the opportunity to update the surcharge on an annual basis.

Q. How will the surcharge be calculated and implemented?

A. The Company's proposed DR reconciliation surcharge calculation methodology is supported by Company witness Miller. The Company proposes to use the calculation methodology in future DR reconciliation proceedings to implement surcharges to refund any overcollections, collect any under recoveries, and for recovery of DR performance incentives. In addition, the Company is proposing to implement DR surcharges designed to refund the over recovery approved in Case No. U-20164, along with the over recovery proposed by the Company in Case No. U-20563, following Commission approval in this proceeding. If the Commission approves any variation of the Company's reconciliation proposal, or if the 2018 reconciliation is not completed or is altered, the Company requests the proposed surcharges be adjusted to appropriately refund or collect all amounts related to the 2017 and 2018 DR reconciliations.

Q. Please explain the structure and projected costs of the Business DR Program.

A. Projected Business DR Program O&M cost for the test year are $15.7 million, included on Exhibit A-75 (SQM-2), page 5. Capital costs for this program are projected to be $3.7 million from 2019 through the test year and are included in Exhibit A-12 (SQM-1), Schedule B-5.5. These capital costs are an increase over the amount approved in the IRP due to increased material, labor, and support costs now projected compared with original estimates prepared for the IRP in 2018. Additionally, the Company is expecting to install more metering devices in 2020 due to the increasing number of Business DR participants. Each business customer that signs up for the Business DR Program is contracted for a specified load (kW) reduction. The Company works with individual business customers to set up a demand reduction plan at their facility that will be implemented when a DR event is called, i.e., a time when electricity demand and cost tend to be highest. A number of business customers of different sizes participate through this process to create a business DR portfolio. When the Midcontinent Independent System Operator, Inc. ("MISO") expects the grid to be strained because of high electric demand or during high market costs, the Company will notify participants within the Business DR Program up to 24 hours in advance of the event, informing them of when they need to reduce load. When the event occurs, these customers have agreed to follow their established demand reduction plan. The resulting reduction in peak load is for the purpose of relieving stress on the electric system in a more cost-effective manner than purchasing capacity from the market or building additional generation resources.

Q. How does the Business DR Program differ from the Company's interruptible rate?

A. The Company's interruptible rate is a filed tariff rate with specific capacity and energy billing parameters, whereas the Company's Business DR Program provides a contract with customers to compensate them for reducing demand. With the interruptible rate tariff, customers are charged a lower rate in exchange for a firm commitment to reduce demand by a specified amount during MISO events. Participants who choose to deviate from this commitment during MISO events are assessed a significant financial penalty. The Business DR Program also comprises demand curtailment commitments. But unlike the Company's interruptible rate tariff, customers choose to nominate an amount of demand they are willing to reduce during events for the program year of June 1 through September 30. There are direct financial penalties assessed to DR customers who do not meet 100% of their accepted capacity reduction during events. If a customer fails to deliver 100% of its total nominated kW for an Emergency Event, the customer shall forego all payments if the average delivered capacity for the event is less than 70% and the customer shall be assessed the real time commodity price ($/MWh), as determined by the MISO Midwest Energy Market, for the kW curtailment which was underperformed per event. The real time commodity price is capped at $1,000/MWh. The financial benefit to participating business customers is less significant with the Business DR Program than with the interruptible rate to recognize the reduced risk for customers. Proper management of the portfolio of customers, in terms of diversity and event management, ensures a resource that delivers predictable capacity as a Load Modifying Resource ("LMR") in the MISO market.

Q. What benefit does the Company's Business DR Program provide?

A. As electric demand varies by season and the grid must support potential full capacity, some energy-generating resources are rarely fully utilized outside of high-demand summer months. DR programs help manage capacity without the need for additional supply-side electricity generation or entering into capacity contracts. Ultimately the program helps balance Michigan's electricity needs.

Q. How many MW of business DR were enrolled in 2019?

A. The Company entered into contractual agreements with business customers under the Business DR Program for the 2019 MISO Planning Year, resulting in a 111.6 MW capacity portfolio as a registered resource with MISO. For the 2020 MISO Planning Year, the Company projects it will enroll additional business customers for a total of 180 MW registered with MISO. For the 2021 MISO Planning Year, the Company projects it will enroll additional business customers for a total of 240 MW registered with MISO.

Q. How are participants compensated for reducing their electric load during peak demand events?

A. Participants are compensated for capacity and energy reductions during events. The capacity payment is tied to kW of reduction nominated, and the energy payment is based on kWh reduction during events. Both are measured from an established baseline in accordance with MISO calculations. Compensation for capacity is based on the customer's contracted capacity reduction during the program enrollment period. The customer receives payment for energy based on performance during events. Incentive payments are priced for market competitiveness and are a component of the overall cost of having and managing a DR capacity resource. These payments are made to customers through a bill credit at the end of the program year.

Q. Do non-participating customers benefit from the Company offering a Business DR Program?

A. Yes. The Company's Business DR Program provides a flexible, repeatable, and scalable capacity resource. By offering the Business DR Program, all Consumers Energy customers benefit by reducing the need to purchase additional capacity during times of peak demand, and thus reducing the cost of providing power to all customers.

Q. Will the terms of the DR contracts executed with customers be 12 months or longer?

A. Yes. The minimum requirement for a contract under the Business DR Program is a 12-month commitment. Additionally, the Company currently offers the option for a customer to sign up for a 4-year commitment to the Business DR Program.

Q. Will these DR contracts be bid into MISO?

A. Yes. The Company will bid into MISO based on the portfolio capacity of participating customers. Each participating customer will be required to enter into a contract with the Company, which outlines the terms of performance in keeping with MISO requirements for an LMR and payments as it relates to the contracted capacity and energy. Capacity payments are standardized at the same rate for all participating customers.

Q. Is the Company proposing any DR-related rates for the Commercial customer class?

A. Yes. The Company is proposing a General Service Interruptible ("GSI") Provision for Secondary Commercial customers served on Rate GSD and Rate GSTU.

Q. Why is the Company proposing a GSI Provision?

A. The Company is looking to provide an option for all customers to participate in DR programs to support the existing IRP and the Company's Clean Energy Plan. But there is a lack of rate options or provisions for General Service customers, and the Company is proposing the provision to provide such options.

Q. How will the GSI Provision be structured?

A. The GSI provision will be an optional, interruptible program for customers. The proposed provision will provide customers with a monthly bill credit for all kWh used at the location. This bill credit is provided as the capacity enrolled on this provision would be registered into the MISO capacity market as an LMR and would meet all the existing requirements for customer notification, curtailment, and participation in MISO System Emergency events. All metered load at a customer location taking part in this provision would be required to interrupt and comply with MISO and Company notifications on LMR dispatch. Company witness Miller discusses the rate mechanism.

Q. Please explain the structure of the Residential DR Program.

A. The Company offers three Commission-approved Residential DR programs: a central Air Conditioning ("AC") Peak Cycling Program, a Dynamic Peak Pricing Program, and a Bring Your Own Device ("BYOD") Program. Projected O&M costs for the test year for these programs of $18.9 million are included on Exhibit A-75 (SQM-2), page 5. Capital costs for these programs are projected to be $32.1 million from 2019 through the test year and are included in Exhibit A-12 (SQM-1), Schedule B-5.5. These capital costs are an increase over the amount approved in the IRP due to increased material, labor, and support costs now projected compared with original estimates prepared for the IRP in 2018. Most of the increase in capital spending is related to increasing the Company's ability to target and enroll (or "activate") customers intested in participateing in DR. Unlike traditial investment in fixed assets like power plants, DR is voluntary and requires customer participation. Customer participation is essential to maximize DR effectiveness and allow the Company to meet its clean energy plan as laid our in the IRP. Investment in the Customer Intelligence & Analytics project will deliver advance analytic models which will indicate which customers will benefit most from participation in the DR program. This information can be used to create targeted customer activation campaigns increasing likely participation while lowering the overall cost of DR customer communication. These analytics models will also continuously update based on most recent information becoming more precise over time. Increasing the Company's ability to activate customers in DR programs is vital in achieving the goals of the clean energy plan.

Q. Please describe the residential AC Peak Cycling Program.

A. In the AC Peak Cycling Program, the Company installs a load control switch on the outside of a customer's home on or near the customer's central AC unit. During peak event days, the Company activates the switch to cycle the output of the central AC unit by 50% to reduce load during the event. The central AC unit cooling system returns to normal once the cycling event ends.

Q. Please describe the direct benefits customers receive for participating in the AC Peak Cycling Program.

A. Customers participating in the AC Peak Cycling Program receive a monthly bill credit of $8.00 during the billing months of June through September. The customer also receives a $25 Visa gift card when initially joining the program.

Q. Please describe the residential BYOD Program.

A. This BYOD Program is for customers who have central AC and a Wi-Fi enabled smart thermostat. The program uses cloud-based software deployed through the customer's Wi-Fi thermostat to perform a day ahead energy optimization of the home to achieve greater demand savings.

Q. Please describe the residential Dynamic Peak Pricing Program.

A. The Company's Dynamic Peak Pricing Program is designed to encourage customers to shift their energy consumption to off-peak hours by providing less expensive rates at these times. As an example, customers are encouraged to change thermostat settings, wait to run their dishwasher, and make other small changes that would lower their monthly energy bill. The more energy usage participants shift from peak hours to off-peak hours, the more they can save. In addition, the program provides incentives for customers to reduce their energy use further during DR events. Currently, the Company offers two pricing options under the program, Critical Peak Pricing and Peak Rewards. The goals of the two pricing options are identical, but the approach to achieve them differs. The Critical Peak Pricing option replaces the standard on-peak energy charge participants pay with a much higher critical peak energy charge in exchange for lower off-peak rates. This is generally referred to as a "stick" incentive to encourage customers to shift demand. Alternatively, the Peak Rewards option offers customers a payment for reducing their energy usage during peak events. This is generally referred to as a "carrot" incentive.

Q. Is the Company proposing changes to its residential DR programs in this case?

A. Yes. The Company is proposing a change to the tariff language to allow the Company to call test events for its Direct Load Administration programs to ensure the resources will respond when called upon. Additionally, with the rollout of the Summer TOU Rates in 2020, the Dynamic Peak Pricing Program peak periods will change to align with those of the Summer TOU rate with a credit for reducing consumption during DR events (Peak Time Rewards) or a charge for increasing consumption during DR events in exchange for lower off-peak rates (Critical Peak Pricing) as authorized in the settlement agreement approved in Case No.

U-20134. The Company is also proposing a change from $0.95 to $1.00 per kWh shifted for Peak Time Rewards customers to simplify communication and outreach to customers. Additionally, the Company is proposing updates to the AC Peak Cycling tariff language to auto-enroll customers into the AC Peak Cycling program if they move into a home that has an existing AC Cycling switch. Upon move in, the customer will be notified confirming participation in the Peak Power Savers-AC Peak Cycling Program and will have 30 days to opt out of the program.

Q. Is the Company proposing any additional residential DR pilots in this case?

A. Yes. The Company is requesting $3.2 million in pilot funding for a Customized Load Control Switch pilot and Back-Up Generator pilot, as outlined in the Company's 2018 DR Reconciliation filing in Case No. U-20653. The pilot funding will also test technologies and concepts that are not yet identified. The Customized Load Control Switch technology has the capability to reduce electricity consumption during periods of peak demand across a variety of end-use devices for winter and summer peaks. The customized load switch would enable the Company to cycle power levels to several different end-use devices during peak times on event days when electricity demand is the highest. This pilot will focus on electric water heaters, pool pumps, and hot tub controls. The advantage of this switch is that it allows multiple load control switches to be installed during the same home visit to maximize the benefits from available DR resources. This will allow for further investigation into the viability of pool pumps and hot tub load control with minimal added effort over a more established water heating load control program. The Company will seek to offer the pilot to the Company's electric customers who currently participate in the AC Peak Cycling Program because this customer base is already familiar with and receptive to utility-controlled demand reduction programs. Customers who participate in the program will be eligible to receive enrollment and event participation incentives. With this pilot design, the Company will provide customers with load control equipment and professional installation at no cost to the customer. Estimated savings potential for the load control switch differs by end-use application, ranging from 0.6 kW per unit for water heater installations to 1.8 kW per unit for pool and hot tub applications.

The second pilot is a residential Back-Up Generator pilot. The Company will make the pilot available to residential customers with standby generators, notify them in advance, and remotely shut off power to the home at the meter during peak events. This will trigger the generator's automatic throw switch which provides auxiliary power to the home for the duration of the event, thereby taking the entire home's demand offline. Estimated savings potential for the Back-Up Generator pilot are 5.0 kW/customer. Customers who participate in the program will be eligible to receive enrollment and event participation incentives.

VI. SUMMARY

Q. Please summarize your direct testimony.

A. The Company projects $88.7 million in O&M expenses in the test year and $49.9 million in capital from 2019 through the test year to support the work within the CX&O organizations, including $36.9 million in capital and $34.7 million of O&M to support electric DR. Exhibit A-12 (SQM-1), Schedule B-5.5 and Exhibit A-75 (SQM-2) detail the capital and O&M expenses related to this work for the test year ending December 31, 2021. In addition, the Company is projecting $17.8 million in capital and $2.9 million in O&M expenses associated with IT projects supporting the work in the CX&O organizations. A list of these projects is presented in Exhibit A-76 (SQM-3). Additional detail regarding the Company's proposed electric DR surcharge is supported by Company witness Miller.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

HUBERT W. MILLER III

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Hubert W. Miller III, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Rate Analyst within the Rates and Regulation Department.

Q. Please describe your qualifications.

A. In May 2002, I graduated from the University of Michigan-Flint with a baccalaureate in Economics. In May 2008, I graduated from Eastern Michigan University with a Masters in Applied Economics and in May 2014 with a Masters in Mathematics. I have also attended various industry seminars addressing marginal cost pricing, the benefits of financial hedges in power markets, the use of dynamic pricing to promote energy efficiency, and the use of statistically adjusted end-use models to forecast electric deliveries.

In September 2002, I accepted the position of Rate Analyst in the Pricing section of the Rates & Regulation Department with Consumers Energy. In this position, my primary responsibilities included electric and natural gas rate design, industry research, and various financial studies. In November 2004, I was promoted to the position of General Rate Analyst, which expanded the scope of my duties to include sponsoring rate design testimony and exhibits in filings with the Michigan Public Service Commission ("MPSC" or the "Commission"). In April 2009, I was promoted to the position of Senior Rate Analyst, which expanded my responsibilities to include coordinating the electric and natural gas rate design models, as well as financial forecast studies associated with the Company's electric contribution in aid of construction.

In February 2012, I accepted a position as a Senior Analyst in the Company's Economic Portfolio Management Department to analyze the benefits of technology investment initiatives for increasing operational efficiency, research the use of algorithms to optimize operational performance, and assist in identifying operational risks to electric and gas distribution assets.

In February 2013, I accepted a position as a Principal Analyst in the Rates & Regulation Department. In this capacity, I was responsible for preparing the Company's official electric and gas delivery and customer forecasts, sponsoring these forecasts in regulatory filings, industry research, and various economic studies.

In February 2015, I accepted a position as a Regulatory Analyst in the Regulatory section of the Energy Efficiency and Renewables Department to provide regulatory and empirical analysis supporting the recovery of the annual energy efficiency program investments, coordinate and maintain the Company's energy efficiency models used in portfolio optimization and benefit-cost analyses, and collaborate with other team members in researching various energy efficiency policies in the electric and gas industries. In May 2017, I was promoted to Regulatory Reporting Manager. In this capacity, I was responsible for coordinating the regulatory filing, reporting, and quality processes associated with the Company's Energy Efficiency Plans, Renewable Energy Plans, and residential Demand Response ("DR") programs.

In February 2019, I returned to the Rates and Regulation Department as a Principal Rate Analyst to focus on the rate design initiatives being considered across the industry.

Q. Please list the MPSC cases in which you have testified.

A. I have testified in the following MPSC cases:

Case No.	Description
U-14547	2006 General Natural Gas Rate Case;
U-15001-R	2007 Power Supply Cost Recovery ("PSCR") Reconciliation;
U-15245	2008 General Electric Rate Case;
U-15415-R	2008 PSCR Reconciliation;
U-15675	2009 PSCR Plan;
U-15744	Stranded Cost Recovery Reconciliation;
U-15805	Public Act 295 Renewable Energy and Energy Optimization Compliance Case;
U-16045	2010 PSCR Plan;
U-16191	2010 General Electric Rate Case;
U-16485	2011 Gas Cost Recovery ("GCR") Plan;
U-17281	2012 Energy Optimization Plan Reconciliation;
U-17301	2013 Biennial Renewable Energy Plan Review Case;
U-17317	2014 PSCR Plan;
U-17334	2014 GCR Plan;
U-17351	2014 – 2017 Amended Energy Optimization Plan;
U-17429	Certificate of Necessity for the Thetford Generating Plant;
U-17643	2014 General Natural Gas Rate Case;
U-17678	2015 PSCR Plan;
U-18331	2016 Energy Efficiency Plan Reconciliation;

U-20134	2018 General Electric Rate Case;
U-20164	2017 DR Reconciliation; and
U-20322	2018 General Natural Gas Rate Case.

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

A. I am sponsoring the rate design and charges recommended to collect the Company's test year revenue requirement of $4.38 billion based on the electric sales forecast of 34,131 Gigawatt-hours ("GWh"), sponsored by Company witness Eugene M. Bruering, and Version 2 of the test year cost-of-service study ("COSS"), sponsored by Company witness Josnelly C. Aponte. As part of my testimony, I am also addressing the design of the Company's recommended Distributed Generation ("DG") tariff; net transmission benefits associated with the Company's Long-term Industrial Load Retention Rate ("LTILRR") tariff; and calculation of test year surcharges to collect the Financial Compensation Mechanism ("FCM"), Conservation Voltage Reduction ("CVR") incentive, and electric rate case deferral, as well as to refund the overrecovery of 2017 and 2018 DR funds.

Q. Please summarize the Company's position on each of these topics.

A. Rate design requires a balancing of multiple objectives—often representing differing views of various stakeholder interests—regarding the best approach for the utility to provide safe, reliable, and affordable power to customers. If done properly, rate design can encourage an efficient use of the electric grid and reduce costs while providing the utility with a fair opportunity to earn a reasonable return on its investments. If done poorly, however, it can reduce efficiency and equity (fairness) by distorting the price signals used to inform customers of the cost to serve them and increase the financial risk to the utility. In designing the test year rates for the Company, a great deal of effort was taken in considering the various stakeholder perspectives on the appropriateness of advanced rate designs, such as time-of-use ("TOU"), real-time pricing, and demand-based rates. This included discussing the various features of alternative rate design structures with other industry experts, as well as reviewing other regulatory filings and writings addressing the topic. Based on the Company's review and assessment of the rate design issues, the Company recommends that the Commission:

(i) Maintain the current TOU residential rate design structures agreed to in the Settlement Agreement of the Company's previous electric rate case (Case No. U-20134) with four modifications. The first modification is to increase the Critical Peak Pricing charge and Peak Time Rebate credit from $0.95 per kilowatt-hour ("kWh") to $1.00 per kWh as a way to encourage more customer participation in these DR programs. The second modification is to approve a Low-Income Assistance Credit ("LIAC") to help increase assistance for some of the Company's most vulnerable customers and to allow recovery of the credit in a similar fashion to that used for the Company's current residential income assistance provision. The third modification is to approve a $1.00 per month increase to the residential system access charge as a partial movement toward the level suggested in the Company's test year COSS. The fourth modification is to increase the consistency across the three residential TOU rate options by aligning the charges assessed for equivalent time periods in each option;

(ii) Approve closing the secondary and primary class flat energy rates (GS and GP) to new business as the first step in transitioning all business customers to more advanced TOU rate designs (GSTU or GPTU) that better reflect the cost of providing service;

(iii) Approve the Company's proposal to add a small interruptible provision to its secondary TOU and demand-based rate options (GSTU and GSD) as a way to provide a DR option for small business customers. Today, these customers have no available options;

(iv) Increase consistency across the secondary business class rate options by approving the Company's proposal to use uniform delivery rate structures for GSTU and GSD. In addition, the Company recommends that the Commission approve its proposal to update its power factor adjustment for the secondary class to align with the adjustment mechanism used for the primary class; and

(v) Approve the Company's proposal to transition customers taking service under its existing light emitting diode ("LED") rate option, GU-XL, to a new rate design structure as a way to improve customer insight into the charges assessed to collect the production and delivery costs associated with providing street lighting service. In addition, the Company proposes that the Commission approve a four-year credit for municipal street lighting customers who have already paid to upgrade to LED lights.

Furthermore, in Case No. U-18383, the Commission directed the Company to file a DG tariff in its next post-June 1, 2018 rate case based on the Inflow/Outflow billing mechanism ("Inflow/Outflow method"). The Company agrees that the Inflow/Outflow method is superior to its existing net metering program in that it more accurately captures the benefits and costs attributed to DG in a way not possible under traditional net metering. To that end, and in compliance with the April 18, 2018 Order in Case No. U-18383, the Company recommends that the Commission approve its proposal to replace its current net metering tariff with the proposed DG tariff, including the Inflow/Outflow method, filed in this case.

The Company is also requesting approval of a LTILRR tariff in this case as a way to retain key customer load that is found to reduce the overall transmission cost borne by the Company's other customers when kept versus not. To determine if other customers benefit, Company witness Michael P. Kelly asked me to calculate the long-term net benefit associated with offering the LTILRR tariff. Based on my analysis, I find that using the LTILRR to retain key customer load is expected to offset the transmission costs to other customers by approximately \$153.5 million over the life of the tariff. As such, the Company is asking that the Commission consider the results of my net benefit calculation when evaluating the merits of this tariff.

In addition, the Company is proposing a surcharge to collect \$3.0 million associated with the approved FCM incentive, a \$0.8 million incentive associated with its investments in CVR, and $12.6 million associated with the deferred recovery of its distribution investments. The Company is also proposing a surcharge to refund $2.1 million associated with an overrecovery in its 2017 and 2018 DR programs. I have designed each of these surcharges consistent with the nature of expense being considered and the Company requests that the Commission approve these surcharges as designed for implementation in 2021.

Q. What is the overall rate impact by customer class under the Company's proposed rate design in this case?

A. As shown in Exhibit A-16 (HWM-1), Schedule F-2[1], and in Figure 1 below, the overall increase in electric rates is primarily driven by an increase in delivery investments. The electric rates for the residential class are projected to increase the most and the primary class the least. The residential rate increase of 14.0% is attributed to increased investments in delivery services and a higher allocation of production costs in the COSS. The electric rates for small and medium sized business customers taking service under the Company's secondary voltage level are projected to increase 2.9% due to increased investments in delivery services, partially offset by a lower allocation of production costs in the COSS. The primary level rates are projected to decrease 6.1% due to a 2.6% increase in delivery system investments offset by an 8.7% reduction in allocated production costs in the COSS. Electric rates for the street lighting class is projected to decrease based on improvements in identifying the delivery system costs associated with street lighting in the COSS and a lower allocation of production costs. I will expand on the nuances of these rate impacts, including deviations from the COSS, in the rate design section of my direct testimony.

[1] Exhibit A-16 (HWM-1), Schedule F-2, provides a summary of the proposed changes in revenues by rate class, schedule, and service.

Please see the direct testimony of Company witnesses Richard T. Blumenstock and Aponte for deeper insights into the delivery system investments and allocation factors used in the COSS, respectively.

Figure 1—Percentage Impact by Class

Class	Production	Delivery	Total
Residential	5.0%	9.0%	14.0%
Secondary	-2.5	5.4	2.9
Primary	-8.7	2.6	-6.1
Lighting	-3.5	-1.7	-5.2
Total	-0.4%	6.4%	5.9%

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following nine exhibits:

Exhibit A-16 (HWM-1)	Schedule F-2	Summary of Present and Proposed Pro Forma Revenues by Rate Schedule;
Exhibit A-16 (HWM-2)	Schedule F-2.1	Calculation of Rate Design Targets;
Exhibit A-16 (HWM-3)	Schedule F-3	Present and Proposed Revenue Detail;
Exhibit A-16 (HWM-4)	Schedule F-4	Comparison of Present and Proposed Monthly Bills;
Exhibit A-77 (HWM-5)		Long-term Industrial Load Retention Rate (LTILRR) Net Benefit Analysis;
Exhibit A-78 (HWM-6)		Calculation of the FCM Incentive Surcharge;
Exhibit A-79 (HWM-7)		Conservation Voltage Reduction (CVR) Incentive Surcharge;
Exhibit A-80 (HWM-8)		Demand Response (DR) Reconciliation Surcharge; and

Exhibit A-81 (HWM-9)	Electric Rate Case Deferral Surcharge.

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

A. Yes.

Q. How is the remainder of your direct testimony organized?

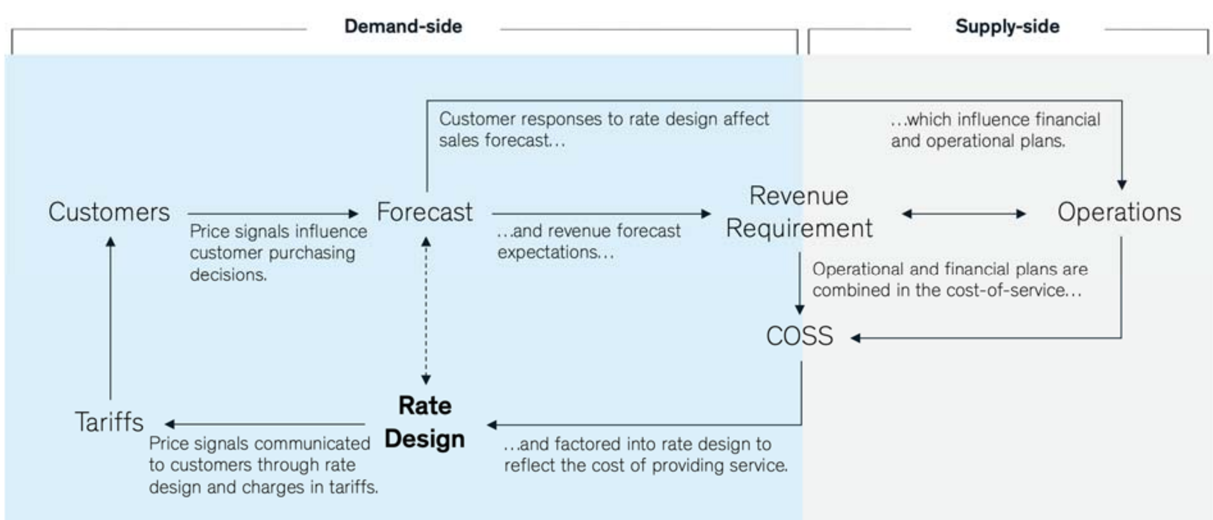
A. The remainder of my direct testimony is separated into four main sections. The first section describes the objectives and methodologies used in designing the test year electric rates in this case. The second section explains why the Company supports the Inflow/Outflow method for its DG Program and why rate design plays an important role in ensuring the DG Program is fair and efficient. The third section describes the method used by the Company to calculate net transmission benefits associated with the LTILRR tariff. The final section describes the calculation of various surcharges requested by the Company in this case.

I. <u>ELECTRIC RATE DESIGN</u>

Q. Please briefly describe where rate design fits within the rate case process.

A. At a macro level, rate design can be thought of as conduit on the demand-side of the equation for translating the cost of providing service delineated in the COSS into actionable information for customers to use when deciding whether to purchase service from the Company or to invest in a substitute product, such as energy efficiency or self-generation (Figure 2). That is, the function of rate design is to translate the results of the cost of service and other ratemaking objectives into charges that customers accept and use to inform their energy consumption. When done well, rate design can serve as an effective component of the ratemaking process that helps in balancing supply with customer demand. But when done poorly, it can cause imbalances and inefficiencies that result in increased costs to the utility and, ultimately, to customers. Indeed, the perceived financial and operational uncertainty associated with some rate designs have slowed progress toward the full-scale use of more efficient and fair designs. For example, many electric utilities across the country continue to rely on simple, flat energy rate designs for the residential customer class since there is little incentive for them to increase both their billing costs and potential financial risk to shareholders from implementing alternative rate designs. While proponents of more advanced designs have downplayed these concerns, others point to the fact that customers do respond to price signals and that changes in behavior should be incorporated in the forecast. Either way, rate design serves an important role in the rate case process, and care should be taken to understand how significant changes in design affect consumer behavior and the utility.

Figure 2—Rate design is the translation of costs into actionable information for consumers



Q. Please describe the primary objectives of rate design.

A. As mentioned earlier in my testimony, rate design requires a balancing of multiple objectives to ensure rates are fair and efficient. Relying on any one objective is likely to produce rates that send inaccurate price signals and result in increased costs to customers and financial risk to the utility. For instance, designing rates to recover all production capacity costs in the summer months to discourage energy use during on-peak periods would increase the likelihood of extreme summer bills to customers and hinder the utility's ability to fairly recover its revenue requirement. Handcuffing rate design to only one objective in this way would more likely result in public resentment and decreased support of TOU rate designs.

Consistent with the rate designs approved in prior cases, the Company used the following four key objectives to inform the rate design in this case. The first objective was to adhere to the cost of service in accordance with the requirements set forth in 2008 PA 286 ("Act 286"). The Company did deviate from the COSS in a couple instances, and the rationale for doing so will be further elaborated below. The second objective was to design rates that encourage the efficient use of the Company's electric system. This means setting rates that accurately reflect the type of cost (fixed versus variable) as well as the temporal nature of certain costs, such as the increased cost of providing energy during peak seasons and times of day. The third objective was to design rates that promote a favorable business climate. For example, providing various rate structures and designs that encourage the location and expansion of business operations in the Company's service territory. The fourth objective was to design stable rates that customers would accept and that would provide the Company with a fair opportunity to collect its revenue requirement. Although I've used an ordinal ranking to describe each of these objectives, this should not be taken to mean one objective is always and exclusively greater in importance than another. In many ways, acceptability and stability of rate design is just as important in effectively serving customers as adhering to the cost of service or promoting a supportive business environment.

Q. Please describe the cost-of-service requirements set forth in Act 286.

A. Section 11 of Act 286 requires electric utilities to design rates that reflect the cost of providing service to each customer class. In other words, costs assigned to one class cannot be reassigned to another without cost justification. The intent being to prevent, or at the very least limit, interclass subsidies. However, this does not completely remove the utility's ability to maintain crossing-points between rates within a class or for the Commission to approve low-income and senior citizen credits. As mentioned above, the Company deviated from the COSS in some instances. I have identified these deviations as adjustments to the class COSS in Exhibit A-16 (HWM-2), Schedule F-2.1.

Q. Please describe the reasons for making these adjustments.

A. Consistent with prior electric rate cases, the Company recommends eight standard adjustments to the assignment of costs across the various rate classes and schedules as part of rate design. The first adjustment, shown on Exhibit A-16 (HWM-2), Schedule F-2.1, line 2, reflects the reallocation of DR credits recovered through base rates as a way to reflect the reduced capacity requirements associated with these programs. While this is consistent with the rate design approach agreed to in the Settlement Agreement of the Company's last electric rate case (Case No. U-20134), the Company is currently evaluating the impact and practicality of incorporating these programs in its load study used to develop the COSS. The initial results of the Company's analysis are described by Company witness Aponte on pages 31 and 32 of her direct testimony in this case but are not being recommended as a change at this time. As such, the Company recommends continuing this adjustment until it is fully incorporated into the cost-of-service load study. If the Commission deems it reasonable to progress with adjusting the Company's load study for the DR programs in this case, then this adjustment is de facto no longer necessary and should be removed.

The second adjustment, shown on line 3, reflects the assignment of capacity costs to the Company's large industrial critical-peak rate, EIP. As an interruptible resource, the EIP rate is excluded from the allocation of production capacity costs in the COSS. But, unlike the other interruptible services, the COSS does not differentiate between firm and interruptible load for EIP since these customers have the ability to "buy through" the events. The result is that neither type of load (firm nor interruptible) is assigned production capacity in the cost study. As such, this adjustment is necessary to reflect the fact that a portion of the EIP load is indeed firm.

The third adjustment, shown on line 4, reflects the difference between the market cost of production capacity collected from large standby customers taking service under rate GSG-2 and the embedded cost of capacity allocated to them in the COSS. Two similar adjustments—the fourth and fifth—are made for both production energy and transmission costs, shown on lines 8 and 14, respectively. In total, these three adjustments suggest that large standby customers pay slightly less under the market-based rate design structure for production and transmission standby service than they would under an embedded cost-of-service design. While this may warrant further evaluation in the event large standby services increase, the adjustments are relatively small at this time. As such, the Company is not recommending any changes to its standby service Rate GSG-2 in this case.

The sixth adjustment, shown on line 19, is used to correct for an over allocation of substation costs to voltage levels 1 and 2 rates as part of the COSS. In the prior electric rate case, Case No. U-20134, it was brought to the Company's attention that it was inadvertently over allocating substation costs to the higher voltage level rates by excluding customer-owned substations from its COSS. To remedy the issue, the Company agreed to reassign the portion of substation costs by allocating those costs to customers who owned their substation in the COSS as part of rate design. The easiest way to accomplish this was to allocate the substation ownership credits across the rate classes based on the distribution allocators developed in the COSS.

The seventh adjustment, shown on line 20, represents a transfer of delivery costs within the streetlighting class between the Company's unmetered streetlighting rates LED and GUL. The Company recommends this intra-class transfer to better align the rate change between the two rate options. The last adjustment, shown on line 21, reflects the lifeline credits (senior citizen and low-income) that have traditionally been supported by all customer classes. Unlike the other approved adjustments, however, the lifeline adjustment is not cost justifiable. Instead, it is based on the Commission's authority to approve special senior citizen and low-income rates granted under Section 11 of Act 286.

Q. What is the overall impact of these adjustments by rate class?

A. Making these eight adjustments to the allocation of costs results in a small decrease of 0.6% to the rate design target of the residential class and a small offsetting increase for the commercial and industrial rate classes.

Q. Please explain the Company's approach in designing rates to collect its production costs.

A. Production represents approximately two-thirds of the Company's cost of providing service and comprises both fixed and variable costs, which are separated in the COSS between capacity (fixed) and energy (variable) costs. In casual terms, production capacity represents the cost of building a generating plant, or purchasing capacity, and having it stand ready to serve customer demand over an extended period of time (annually) or at a certain hour (peak). Conversely, production energy represents the cost of running these plants and is usually attributed to fuel expenses. Traditionally, the Company has used a combination of forecasted and actual prices based on the Midcontinent Independent System Operator, Inc. ("MISO") market as a way to estimate the capacity and energy cost spread of providing service during different time periods. In this case, the Company recommends two changes to the method used for estimating the price spreads going forward. The first change is to use only the actual real-time Locational Marginal Price ("LMP") from the years 2014 to 2019 to calculate the energy charge spreads for the various TOU rates. While the mean forecasted LMP is reasonable, the variance in the forecasted hourly values is narrower than past actuals and underrepresents the expected time differential in marginal energy prices that will be observed in 2021. To that end, the Company recommends excluding the forecasted hourly LMP and using the 2014 to 2019 actual hourly LMP results in designing the TOU energy charges.

The second change is to design the production capacity portion of rates to collect the portion of fixed plant costs in each period based on the expectation of serving customer demand during that time based on the latest hourly load study for each class (MISO Cost of New Entry) and allocated production capacity in the COSS.

Q. Please explain the Company's approach in designing its residential customer class rates.

A. As mentioned in my summary, the Company is recommending the Commission maintain the currently approved residential rate design structure with four modifications. The Company's overall objective in designing the residential rates was to provide a sense of stability for this class by retaining the recently approved rate structure for each option (Residential Summer On-Peak Basic Rate, Residential Smart Hours Rate, Residential Nighttime Savers Rate, and Residential Service Secondary Non-Transmitting Meter Rate ("RSM")) while improving consistency and transparency where possible. This was accomplished in three ways. First, the number and types of changes being recommended in this case are limited in scope and scale. Second, the collection of charges within the available rate options were evaluated based on how each fit individually and collectively within in the class. For example, the summer on-peak charges assessed in all three residential TOU options were set equal since each covered the same time period and are intended to inform customers about the cost of providing power during that period. Third, transmission and production expenses were separated to highlight the Company's approach for recovering both and to provide stakeholders in this case with greater insight into the production rates recommended for compensating DG customers who put excess power back on the grid.

Q. Please describe the recommended modifications to the residential rates.

A. The first modification the Company recommends is to increase the critical peak price charge and peak-time rebate credit, assessed during peak events, from \$0.95 per kWh to \$1.00 per kWh as a way to encourage customer enrollment, participation, and retention. This change is based on a request sponsored by Company witness Steven Q. McLean. The second modification is to add a LIAC of $30 per month for 4,600 residential customers. While the details and rationale for this proposal are addressed in the direct testimony of Company witness McLean, I am recommending that the Commission treat recovery of this credit similar to the Company's other residential lifeline credits shown on Exhibit A-16 (HWM-2), Schedule F-2.1, line 21. This is consistent with the approach approved by the Commission in prior cases to recover residential credits, such as income-assistance and senior citizen. The third modification is to gradually increase the residential system access fee to better align this monthly charge with the $10.00 per month amount supported by the COSS. The Company believes that increasing the system access fee from $7.50 per month to $8.50 per month reasonably accomplishes this goal. The fourth modification the Company recommends is to improve consistency in the TOU charges assessed across the residential rates. As discussed earlier, the charges in each rate were evaluated within and across the three residential TOU options.

Q. Please explain why the Company proposes to limit the residential system access fee increase to $1.00 per month.

A. Although the COSS supports increasing the residential system access fee by $2.50 per month, the Company believes that gradually increasing the monthly charge to $1.00 per month is a balanced approach for moving toward rates that send better price signals by reflecting cost causation and maintaining a stable rate design structure.

Q. How is the Company proposing to address residential customers with non-transmitting meters?

A. As described in the testimony of Company witness Brenda L. Houtz, there are approximately 6,600 residential customers with non-transmitting meters. As a temporary solution, the Company is proposing to bill these customers under its residential non-transmitting rate option, RSM, but exempt them from the opt-out fee since they did not elect this option.

Q. Please list the Company's recommended rate design changes to the secondary and primary classes.

A. The Company recommends four rate design changes to its secondary and primary rates. The first is to close the Company's flat energy rates GS and GP to new business. The second is to add an interruptible provision to the secondary TOU and demand-based rate options GSTU and GSD, respectively. The third is to align the delivery charges assessed under GSTU and GSD. The fourth change the Company recommends is to update the power factor adjustment calculation applied under rate option GSD.

Q. Why is the Company recommending that the Commission approve closing its secondary and primary flat energy rates GS and GP to new business?

A. The industry is moving away from the flat energy rate design used by many utilities today toward more advanced and individualized rate designs—such as TOU, demand-based, and subscription-based bills. Indeed, the Company is currently in the midst of transitioning most of its residential customers to a TOU-based rate design. While the Company anticipates completing the residential transition by 2020, it needs time to evaluate the issues and costs with implementing a similar plan for its non-residential classes. As a reasonable first step, however, the Company recommends that the Commission approve Consumers Energy's proposal to close both its secondary and primary flat energy rates (GS and GP) to new business.

Q. What method did the Company use to calculate the secondary level interruptible credit?

A. As described by Company witness McLean, on pages 70 and 71 of his direct testimony, the secondary interruptible provision ("GSI") is intended to provide small and medium sized business customers with an opportunity to pariticpate in DR programs similar to that offered to the Company's larger business customers. As such, the Company calculated the secondary interruptible credits based on the primary class credits applied under the interruptible GI provision. In doing so, the Company is able to send consistent price signals across its business rates while expanding its DR options to customers taking electric service at the secondary voltage level.

Q. Why is the Company recommending the use of a consistent delivery rate design for rates GSTU and GSD?

A. The Company believes it is important to send accurate price signals regarding the cost of delivering power to customers, which are mostly fixed or demand-based costs, and that having a consistent delivery rate design structure across the individual rates within a class is appropriate.

Q. Please describe the rationale for updating the GSD power factor adjustment.

A. As mentioned on page 5 of Company witness Rachel L. Barnes' direct testimony, the Company is proposing to leverage its investments in metering to better align the power factor adjustment across its various business rate options. By making this change, the Company will provide GSD customers with a more transparent power factor adjustment schedule, encourage GSD customers to improve their power factor beyond 90% by offering a credit, and reduce the inconsistency between its business rates.

Q. Please list the recommended rate design changes to the street lighting and unmetered class.

A. The Company recommends two changes to the street lighting class. The first is to replace the Company's current LED rate GU-XL with a simpler and more transparent design. The second is to add a conversion credit for municipal streetlighting customers who had paid to convert from the standard light types to an LED technology prior to the adoption of the current burnout replacement to LED program.

Q. Why is the Company proposing to replace its current LED rate option GU-XL with an alternative design?

A. As part of the settlement in the prior electric rate case, the Company agreed to work with various stakeholders to address issues and concerns customers were having with its streetlighting rates. One issue identified was the difficulty and frustration customers had with determining the amount they were billed for each light. To address this issue, the Company is recommending replacing the current rate design with a tiered structure based on the wattage level of the light. A customer with multiple streetlights at various wattages would receive a monthly bill showing the number of lights and base charges by each wattage tier.[2] To implement this new design, however, the Company is requesting the Commission approve a six month transitional rate, based on the existing rate design structure under GU-XL, until the new LED tiered rate structure can be fully implemented.

Q. Why is the Company proposing a light conversion credit in this case?

A. One concern raised by some stakeholders related to the treatment of costs for municipalities that had paid to convert from the standard lighting technology under rate GUL to the more

[2] Surcharges and the PSCR Factor would continue to be shown as an aggregated amount on the bill.

advanced LED technology. As the Company ramps up its burnout replacement program to convert streetlights across its system, these customers were worried that they would pay twice—once when they paid to have their lights exchanged and again when the system wide conversion of lights at burnout is included in the Company's base rates. To address this concern, the Company is proposing to add a four-year conversion credit for customers who paid to convert to their streetlights to a LED technology prior to the Commission order approving the burnout replacement program in Case No. U-18322.

Q. Which exhibit contains the rate design changes you described above?

A. The present and proposed rate designs are shown in Exhibit A-16 (HWM-3), Schedule F-3. The proposed electric rates are calculated to collect the jurisdictional revenue requirement contained in Exhibit A-16 (HWM-2), Schedule F-2.1. Both the present and proposed electric charges are applied to the billing determinants to calculate the test year revenues shown in Exhibit A-16 (HWM-1), Schedule F-2, and are the source of the proposed charges that appear in the redlined tariffs filed by Company witness Barnes in this case.

Q. What is the monthly bill impact to customers under the Company's proposed rate design?

A. The monthly customer bill impacts for each rate schedule are shown in Exhibit A-16 (HWM-4), Schedule F-4.

II. DISTRIBUTED GENERATION TARIFF

Q. Please provide an overview of the Inflow/Outflow method.

A. The Inflow/Outflow method is an eloquent solution—simple, transparent, and accurate—that leverages investments in advanced metering infrastructure for designing and implementing a DG Program. Under this design, customers with solar or wind generation are billed their normal rates for all power taken from the grid (Inflow) and provided a production credit for all excess generated power put back on the grid (Outflow). In Case No. U-18383, the Commission Staff ("Staff") found this method of billing superior to the current Net Energy Metering ("NEM") design and recommended it as the preferred billing method for replacing the current NEM Program.

Q. Why is this method superior to the current NEM Program?

A. As described in Staff's report, the Inflow/Outflow method is consistent with the notion of cost causation in that it appropriately and accurately reflects how a customer uses the electric system. The use of NEM was adequate for a time before advanced metering provided a way to bill and compensate customers who choose to install renewable generation on their premises. The Inflow/Outflow method leverages improvements in metering infrastructure to provide a more accurate and transparent solution for fairly and efficiently determining the customer's use of the utility's system and compensating DG customers for energy sent to the grid. Reverting back to a NEM design would be a step backward in the progression toward better reflecting costs through investments in technology.

Q. Please provide an example of how the two methods work.

A. The NEM and Inflow/Outflow methods are similar in that the customer is essentially charged the full retail rate for the generated power they use on their premises. Where the two methods differ is in the accuracy of measurement and compensation for excess power put on the grid. Under the NEM design, customers are paid the full retail rate (production, transmission, and delivery) for Category 1, and the power supply component for Categories 2 and 3, on the net amount of energy generated within a month. That is, if a customer takes

100 kWh from the grid in one period, but generates 100 kWh at a different time during the month, then, under the NEM Category 1 design, the customer essentially avoids paying for their use of the system. Conversely, under the Inflow/Outflow method, the same customer is held accountable for their use of the grid by paying the normal production and delivery charges for the 100 kWh of power they take from the grid and is fairly compensated for the 100 kWh of power they produce and put back on the grid. The Company's other customers also benefit in that they are no longer required to fully subsidize these customers.[3]

Q. Why are some stakeholders opposed to the Inflow/Outflow method?

A. Some stakeholders are concerned that moving away from the subsidized NEM design will harm the economics of small scale solar in the state. While I am not taking a policy position as to whether or not it is appropriate for the utility to subsidize those customers who choose to install a certain type of generating technology on their homes, I do not believe that the NEM design conforms with the spirit of sending accurate price signals to encourage efficient investments in the electric system.

Q. How will the Company compensate DG customers for excess power put back on the grid?

A. The Company is proposing to pay its embedded production rates (power supply less transmission) for the excess power from DG customers, which will be applied as an offset to the production section of their monthly energy bill.

Q. Please explain the Company's rationale for recommending this method for compensating DG customers.

[3]Although the instaneous Inflow/Outflow method reduces the level of subsidies, the amount of the remaining subsidy depends on the structure of the rate design used.

A. There were three elements the Company evaluated when deciding which approach to use in setting the compensation credits for excess power. The first was the requirement in Section 177(4) of Public Act 342 of 2016 that established how the compenstation credits would be applied to a customer's monthly electric bill. As described within this section of the law, the credit for excess power must be displayed on the DG customer's bill and is limited to the total power supply charges on that bill. The second element considered was the language in Section 177(4) which provided that the compensation credits shall exclude transmission and delivery charges. The third element was to decide which of the two methods established in subparts (a) and (b) of Section 177(4) should be used in setting the compensation credit. The first method set forth in subpart (a) allows utilities to compensate DG customers based on the monthly average real-time LMP of energy. The second method set forth in subpart (b) of this section allows utilities to compensate customers based on the power supply component of the full retail rate, excluding transmission. Although the method set forth in subpart (a) represents the market value of energy, the Company is proposing to set the compensation credit at the power supply less transmission. The Company has discretion in deciding which of the two methods to propose and believes the compensation method of power supply less transmission is reasonable for the DG Program at this time.

Q. Is it reasonable for the Company to include transmission in the outflow credit used to compensate DG customers for excess power?

A. No. Including transmission in the outflow credit would essentially compensate the homeowner with a private solar array for a service they are not providing, thereby increasing the energy bill of their neighbor. Although some advocates have argued that

DG customers benefit the grid, I have yet to find any compelling research supporting this claim. Indeed, the literature generally suggests that increasing the penetration of solar on the grid increases the intra-day variations in load and may not notably affect the annual load peak of households.[4] As such, the Company believes it is not appropriate to include transmission as part of the outflow credit at this time.

Q. Will DG customers retain the environmental attribute associated with the power they put back on the grid?

A. Yes, the customer will retain the environmental attributes associated with their generation.

Q. Is the Company proposing to limit the number of customers who can install solar panels on their homes?

A. No, absolutely not. The Company is a proponent of renewable energy, as evidenced by its integrated resource plan, and supports the idea of customers exploring whether or not intalling solar panels on their home makes sense. But, the Company also has a responsibility to manage costs by not over paying for power. This means that the Company must balance its support of DG with the higher cost of purchasing the excess power these customers put back on the grid. As such, the Company is proposing to maintain the current caps on the amount of excess power it will purchase at above market prices. This, however, does not preclude a customer who is not participating in the DG Program from installing solar panels on their home as a way to support renewable energy and reduce their monthly electric bill.

[4] Fischer, D., Surmann, A., and Lindberg, K.; Impact of emerging technologies on the electricity load profile of residential areas; Energy and Buildings, 2020; Vol. 208

Q. Can a customer who installs solar generation after the DG Program is fully subscribed still receive compensation for excess power they put back on the grid?

A. Yes, a customer with eligible generation will have the option to sell their excess power to the Company at the standard offer Public Utility Regulatory Policies Act of 1978 ("PURPA") rate. Qualifying customers who are not interested in the standard offer PURPA rate may also be eligible to sell their excess power to the Company at the market price of energy described in Rule C11 of the proposed tariffs in this case.

Q. How would the Company's proposal to compensate DG customers at power supply less transmission change if the Company agreed to increase the DG Program cap?

A. As discussed above, customers who install eligible generation, and are not participating in the DG Program because of the cap, can still sell their excess power to the Company at a price more reflective of costs. However, if the Company agreed to increase the amount of power it would be willing to purchase under the DG Program, then the Company proposes to replace the retail power supply rate recommended above with a more cost-based price for outflow as a way to balance the impact to nonparticipating customers.

Q. Is the cost to serve a DG customer, versus a customer who does not install solar panels on their home, lower?

A. No. While some stakeholders have argued that utilities should pay DG customers for their excess power at prices above the market because they are less costly to serve than other customers, the Company has not seen any compelling evidence to suggest this is the case. The Company actually saw the opposite in its service territory based on the standby cost-of-service work that the Brattle Group completed in late 2019. As shown on page 31 in the direct testimony of Company witness Aponte, the per unit cost of serving residential customers with DG ranges between 20% to 50% more than that of other customers. Some may argue that the higher cost is more a reflection of the fact that more affluent customers with larger homes, and thus more electric load, have traditionally been the ones interested in installing DG. Although I suspect there is some truth to this, I do not believe it justifies having the Company's other customers subsidize DG ad infinitum.

Q. Does the Inflow/Outflow method eliminate the Company's concern of intra-class subsidies?

A. Not completely. Although the Inflow/Outflow method used under the DG Program does substantially reduce the amount of intra-class subsidies relative to the current NEM Program, there is still a subsidy issue with rate designs that primarily recover fixed costs through volumetric charges. That is, the current volumetric TOU rate designs do not effectively reflect the fixed costs of providing grid support services—such as load balancing, reliability, and optionality—which could be achieved with more advanced rate design structures.

Q. Is the Company recommending an alternative rate design structure to refine the price signals sent as part of the DG Program in this case?

A. Not at this time. The Company met and spoke with various stakeholders and industry experts to discuss the benefits and costs of different rate design structures but did not reach a clear concensus amongst them about how best to address designing rates to reduce intra-class subsidies. Most stakeholders agreed that TOU designs were appropriate, but disputed the use of demand charges to recover grid service. While Consumers Energy generally believes there is merit in exploring alternative rate designs, the Company recommends that the Commission approve the Company's plan to stabilize its residential rates, after fully implementing the TOU designs in 2020, before exploring more advanced designs for the residential class. For business customers who install renewable generation between 150 kW and 550 kW, however, the Company recommends they take service under one of the Company's business TOU rate structures.

Q. Are you aware of any business customers who have solar generation of 150 kW or above?

A. Yes, I am aware of six customers taking service under the Company's primary TOU rate GPTU that have installed solar.

III. LONG-TERM INDUSTRIAL LOAD RETENTION RATE

Q. Please describe the method used to calculate the net transmission benefit associated with Consumers Energy offering this tariff.

A. The net transmission benefit to other customers from offering the LTILRR tariff is shown in Exhibit A-77 (HWM-5), and is calculated by comparing the incremental transmission cost to serve the LTILRR tariff to incremental contribution to transmission costs. The difference between the incremental cost to serve and contribution results in a positive net transmission benefit of $153.5 million over the expected life of the tariff. To determine the incremental transmission cost to serve, Company witness Keith G. Troyer provided a forecast of the Company's transmission costs including and excluding the electric load anticipated to be served under this tariff. The incremental transmission contribution was calculated based on the difference between the transmission payment under the LTILRR tariff, as provided by Company witness Kelly, and the transmission payment that would be collected under the Company's large standby rate GSG-2.

Q. Please explain why the Company is using its large standby rate to calculate the transmission costs that would be collected in the absence of offering the LTILRR tariff.

A. In the absence of the LTILRR, key customer load would take standby service from the Company under rate GSG-2.

Q. Does the LTILRR satisfy the requirements set forth in Public Act 348 of 2012?

A. Yes. As explained by Company witness Kelly, the requirements for approving the LTILRR is that it provides a positive net transmission benefit to other customers. As mentioned above, the LTILRR satisfies this requirement.

IV. <u>2021 TEST YEAR SURCHARGES</u>

Q. Please describe the method used to calculate the FCM incentive surcharge.

A. The Company recommends that the Commission approve the FCM incentive surcharge as shown in Exhibit A-78 (HWM-6). The Company proposes to collect a $3.0 million FCM incentive, described by Company witness Troyer, through a volumetric surcharge from its full service customers in the 2021 test year. The allocation of the FCM incentive across the various rates is based on the capacity and energy production cost allocators sponsored by Company witness Aponte in Exhibit A-20 (JCA-6). Given the relatively small size of the capacity component in this case, the Company recommends collecting both the capacity and energy piece through a volumetric charge.

Q. Please describe the method used to calculate the CVR incentive surcharge.

A. The Company recommends that the Commission approve the CVR incentive surcharge as shown in Exhibit A-79 (HWM-7). The Company proposes to collect the CVR incentive of approximately $0.8 million described by Company witness Michael J. Delaney through a volumetric surcharge from its full service and electric choice customers in the 2021 test year. The allocation of the CVR incentive across the various rates is based on the distribution plant allocator 230 sponsored by Company witness Aponte in Exhibit A-16 (JCA-2), Schedule F-1.1.

Q. Please describe the method used to calculate the surcharge to refund the 2017 DR under investment.

A. The Company recommends that the Commission approve the DR surcharge to refund the overrecovery of funds as described by Company witness McLean and shown in Exhibit A-80 (HWM-8). The Company proposes to refund approximately $2.1 million through a volumetric surcharge to its full service customers in the 2021 test year. The allocation of the DR refund is based on the allocation sponsored by Company witness Aponte in Exhibit A-20 (JCA-6).

Q. Please describe the method used to calculate the Electric Rate Case Deferral surcharge.

A. The Company recommends that the Commission approve the Electric Rate Case (“ERC”) Deferral surcharge as shown in Exhibit A-81 (HWM-9). The Company proposes to collect the $12.6 million of ERC Deferral sponsored by Company witness Heidi J. Myers through a volumetric surcharge from its full service and electric choice customers in the 2021 test year. The allocation of the deferral costs across the various rates is based on the allocation sponsored by Company witness Aponte in Exhibit A-20 (JCA-6).

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief. _______________________________________	))))))	Case No. U-20697

DIRECT TESTIMONY

OF

HEIDI J. MYERS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

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

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

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

Q. Please describe your educational background.

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

Q. Please describe your professional experience.

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

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

A. As the Director of Revenue Requirements and Analysis, I am responsible for managing and preparing the following: (i) studies related to the level of the Company's revenue requirements, including the preparation, and monitoring of gas and electric rate case filings before the Commission; (ii) studies related to the Company's overall profitability of its business units; and (iii) other financial analyses related to planning scenarios. In addition, I oversee the calculation of the Company's Gas Cost Recovery and Power Supply Cost Recovery ("PSCR") monthly billing factors.

Q. Have you previously filed testimony with the Commission?

A. Yes.

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

A. I sponsored testimony in the following cases:

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

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

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

Case No. U-17473 – Consumers Energy securitization;

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

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

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

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

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

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

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

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

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

A. In my direct testimony, I will: (i) identify and support the Part 1 exhibits required by the Commission's Order in Case No. U-18238; (ii) present Consumers Energy's revenue deficiency calculation for the projected test year including special analysis related to the Demand Response ("DR") Program and D.E. Karn ("Karn") Units 1 and 2 retention costs; (iii) request recovery of PowerMIDrive pilot program costs; (iv) request recovery of the deferred revenue requirement of certain distribution capital spending approved by the Commission in Case No. U-20134; (v) propose a method of cost recovery for the Financial Compensation Mechanism ("FCM"); (vi) propose a method of cost recovery for the Conservation Voltage Reduction ("CVR") incentive; (vii) present the levelized revenue requirement for the designated resource and the distribution charge for the Hemlock Semiconductor Operations, LLC ("HSC") contract; and (viii) present Advanced Metering Infrastructure ("AMI") business case.

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

A. My direct testimony is divided into eight sections. Section I will present exhibits and supporting testimony on the historical period. Section II will present exhibits and supporting testimony related to the projected test year revenue requirements calculations. Section III will provide testimony regarding the PowerMIDrive pilot program. Section IV presents the deferred revenue requirement of capital spending for certain distribution programs. Section V provides the proposed method of cost recovery related to the FCM. Section VI provides the proposed method of cost recovery related to the CVR incentive. Section VII presents testimony in support of the HSC contract. Section VIII supports the AMI business case.

Q. Please describe the revenue requirements determination.

A. To comply with the MPSC's filing requirements, my direct testimony presents the revenue deficiency for the actual historical period. Additionally, to comply with the MPSC's filing requirements, my direct testimony presents and explains how the revenue deficiency for the future projected test year was developed. I will also reconcile the historic and projected test year periods. Through this filing, the Company demonstrates that it requires a rate increase in order to earn a just and reasonable return.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. The historical test year exhibits are identified in Section I of my direct testimony. The projected test year exhibits are identified in Section II of my direct testimony. Sections III through V identify exhibits supporting PowerMIDrive, the electric rate case deferral, and the FCM, respectively. Sections VII and VIII identify exhibits for the HSC contract and the AMI business case.

Q. Were the exhibits which are presented in your direct testimony prepared by you or under your direction and supervision?

A. Yes.

I. HISTORICAL YEAR

Q. What is the actual historical year used in the exhibits and supporting testimony?

A. The Company selected the 2018 calendar year as the historical year because it is the most recent historical calendar period with final regulatory financial statements that could be used for the filing.

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 (HJM-1)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Historical Year Ended December 31, 2018;
Exhibit A-1 (HJM-2)	Schedule A-2	Financial Metrics;
Exhibit A-2 (HJM-3)	Schedule B-1	Total Rate Base for the Historical Year Ended December 31, 2018;
Exhibit A-2 (HJM-4)	Schedule B-2	Total Utility Plant for the Historical Year Ended December 31, 2018;
Exhibit A-2 (HJM-5)	Schedule B-3	Depreciation Reserve and Other Deductions for the Historical Year Ended December 31, 2018;
Exhibit A-2 (HJM-6)	Schedule B-4	Working Capital for the Historical Year Ended December 31, 2018;
Exhibit A-2 (HJM-7)	Schedule B-5	13-Month Average Working Capital Balance Sheet Summary for the Historical Year Ended December 31, 2018;
Exhibit A-2 (HJM-8)	Schedule B-6	13-Month Average Working Capital Balance Sheet Summary PIT for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-9)	Schedule C-1	Adjusted Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-10)	Schedule C-2	Computation of Revenue Multiplier for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-11)	Schedule C-3	Historical Operating Revenue for the Historical Year Ended December 31, 2018;

Exhibit A-3 (HJM-12)	Schedule C-4	Historical Fuel and Purchased Power for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-13)	Schedule C-5	Historical Operation and Maintenance Expense for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-14)	Schedule C-6	Depreciation and Amortization Expense for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-15)	Schedule C-7	General Taxes for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-16)	Schedule C-8	Federal Income Taxes for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-17)	Schedule C-9	State Income Taxes for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-18)	Schedule C-10	Other (or Local) Taxes for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-19)	Schedule C-11	Allowance for Funds Used During Construction for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-20)	Schedule C-12	Compensation Disallowances Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-21)	Schedule C-13	Dues and Donations Disallowances Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-22)	Schedule C-14	Advertising Classification and Disallowance for the Historical Year Ended December 31, 2018;

Exhibit A-3 (HJM-23)	Schedule C-15	Corporate Giving & Communications Disallowances Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-24)	Schedule C-16	Weather Normalization Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-25)	Schedule C-17	PSCR Adjustments Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-26)	Schedule C-18	Customer Deposit Interest Expense Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-27)	Schedule C-19	Jobwork Revenue Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-28)	Schedule C-20	Jobwork Expense Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-29)	Schedule C-21	Surcharge Revenue, Expense, and Amortization Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-30)	Schedule C-22	Transmission Depreciation Expense Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-31)	Schedule C-23	Property Tax Refund Impact on Net Operating Income for the Historical Year Ended December 31, 2018;
Exhibit A-3 (HJM-32)	Schedule C-24	Tax Effect of Pro-Forma Interest Adjustment for the Historical Year Ended December 31, 2018;

Exhibit A-3 (HJM-33)	Schedule C-25	Tax Effect of Interest Synchronization Adjustment for the Historical Year Ended December 31, 2018;
Exhibit A-4 (HJM-34)	Schedule D-1	Overall Rate of Return Summary for the Historical Year Ended December 31, 2018;
Exhibit A-4 (HJM-35)	Schedule D-2	Cost of Long-Term Debt for the Historical Year Ended December 31, 2018;
Exhibit A-4 (HJM-36)	Schedule D-3	Cost of Short-Term Debt for the Historical Year Ended December 31, 2018;
Exhibit A-4 (HJM-37)	Schedule D-4	Cost of Preferred Stock for the Historical Year Ended December 31, 2018; and
Exhibit A-4 (HJM-38)	Schedule D-5	Cost of Common Shareholder's Equity for the Historical Year Ended December 31, 2018.

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 factors supplied by Company witness Josnelly C. Aponte.

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 (HJM-1), Schedule A-1, is the computation of the electric revenue deficiency for the year ended December 31, 2018. Exhibit A-1 (HJM-2), Schedule A-2, is a multiple page exhibit that provides financial metrics on both a financial basis (pages 1 through 3) and a ratemaking basis (pages 4 through 6) for the years 2013 through 2018. Pages 1 and 4 calculate an electric earned rate of return on common equity for each of these years. The $21,835,000 jurisdictional electric revenue sufficiency is shown on Exhibit A-1 (HJM-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 (HJM-3), Schedule B-1, presents the calculation of average electric rate base for the year ended December 31, 2018 in the jurisdictional electric amount of $10,210,952,000 as shown on line 12, which is carried forward to Exhibit A-1 (HJM-1), Schedule A-1, line 1. Exhibit A-2 (HJM-4), Schedule B-2, through Exhibit A-2 (HJM-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 (HJM-9), Schedule C-1 presents the calculation of adjusted NOI for the year ended December 31, 2018 in the jurisdictional amount of $612,206,000, as shown on line 32, which is carried forward to Exhibit A-1 (HJM-1), Schedule A-1, line 2. Exhibit A-3 (HJM-10), Schedule C-2, through Exhibit A-3 (HJM-33), Schedule C-25, support the development of the various components of adjusted NOI. The Schedule C data for the historical period are generally sourced to the Company's 2018 Form P-521 Annual

Report to the MPSC. In addition, Exhibit A-3 (HJM-13), Schedule C-5, reconciles the historic 2018 Other O&M expense by MPSC account with the amounts in the Company's filed 2018 MPSC P-521 Annual Report, by witness and expense category.

Q. Please describe the Schedule D exhibits for the historical period.

A. Exhibit A-4 (HJM-34), Schedule D-1, presents the overall rate of return summary for the year ended December 31, 2018. The weighted cost of capital of 5.84% is shown on line 11, column (h), and is carried forward to Exhibit A-1 (HJM-1), Schedule A-1, line 4. Exhibit A-4 (HJM-35), Schedule D-2, through Exhibit A-4 (HJM-38), 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. No. I have calculated a historical year jurisdictional electric revenue sufficiency for the 12-month period ended December 31, 2018 of $21,835,000.

Q. Please summarize the key findings for the historical year exhibits.

A. These historical year exhibits demonstrate that for the year ended December 31, 2018:

Jurisdictional	**(000)**
Rate Base	$10,210,952
Adjusted NOI	$612,206
Overall Rate of Return	6.00%
Required Rate of Return	5.84%
Income Required	595,900
Income Deficiency (Sufficiency)	(16,306)
Revenue Multiplier	1.3391
Revenue Deficiency (Sufficiency)	(21,835)

The above information is presented on Exhibit A-1 (HJM-1), Schedule A-1.

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 (HJM-9), Schedule C-1. I will discuss the adjustments and 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 December 31, 2021 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 December 2021 projected test year.

A. The following exhibits support the projected test year:

Exhibit A-11 (HJM-39)	Schedule A-1	Revenue Deficiency (Sufficiency) for the Projected 12 Month Period Ending December 31, 2021;
Exhibit A-11 (HJM-40)	Schedule A-2	Financial Metrics – Ratemaking Basis;
Exhibit A-11 (HJM-41)	Schedule A-3	Comparison of the Electric Revenue Requirement between the Historical Year and the Test Year;
Exhibit A-12 (HJM-42)	Schedule B-1	Projected Rate Base Projected 12 Month Period Ending December 31, 2021;
Exhibit A-12 (HJM-43)	Schedule B-1a	Development of Projected Rate Base Projected 12 Month Period Ending December 31, 2021;
Exhibit A-12 (HJM-44)	Schedule B-2	Total Utility Plant Projected 12 Month Period Ending December 31, 2021;
Exhibit A-12 (HJM-45)	Schedule B-3	Depreciation Reserve and Other Deductions Projected 12 Month Period Ending December 31, 2021;
Exhibit A-12 (HJM-46)	Schedule B-4	Working Capital Summary Projected 12 Month Period Ending December 31, 2021;
Exhibit A-12 (HJM-47)	Schedule B-4a	Working Capital Projected 12 Month Period Ending December 31, 2021;
Exhibit A-12 (HJM-48)	Schedule B-5	Projected Capital Expenditures;
Exhibit A-13 (HJM-49)	Schedule C-1	Adjusted Net Operating Income Projected 12 Month Period Ending December 31, 2021;

Exhibit A-13 (HJM-50)	Schedule C-2	Projected Revenue Conversion Factor Projected 12 Month Period Ending December 31, 2021;
Exhibit A-13 (HJM-51)	Schedule C-3	Projected Operating Revenue Projected 12 Month Period Ending December 31, 2021;
Exhibit A-13 (HJM-52)	Schedule C-4	Projected Fuel and Purchased Power Projected 12 Month Period Ending December 31, 2021;
Exhibit A-13 (HJM-53)	Schedule C-5	Projected Operating and Maintenance Expenses Projected 12 Month Period Ending December 31, 2021;
Exhibit A-13 (HJM-54)	Schedule C-6	Projected Depreciation & Amortization Expenses Projected 12 Month Period Ending December 31, 2021;
Exhibit A-13 (HJM-55)	Schedule C-7	Projected General Taxes Projected 12 Month Period Ending December 31, 2021;
Exhibit A-13 (HJM-56)	Schedule C-8	Projected Federal Income Taxes Projected 12 Month Period Ending December 31, 2021;
Exhibit A-13 (HJM-57)	Schedule C-9	Projected State Income Taxes Projected 12 Month Period Ending December 31, 2021;
Exhibit A-13 (HJM-58)	Schedule C-10	Projected Other (or Local) Taxes Projected 12 Month Period Ending December 31, 2021;
Exhibit A-13 (HJM-59)	Schedule C-11	Projected Allowance for Funds Used During Construction Projected 12 Month Period Ending December 31, 2021;
Exhibit A-13 (HJM-60)	Schedule C-12	Tax Effect of Pro-Forma Interest Adjustment Projected 12 Month Period Ending December 31, 2021;

Exhibit A-13 (HJM-61)	Schedule C-13	Tax Effect of Interest Synchronization Adjustment Projected 12 Month Period Ending December 31, 2021; and
Exhibit A-13 (HJM-62)	Schedule C-14	Development of Net Operating Income Projected 12 Month Period Ending December 31, 2021.
Exhibit A-82 (HJM-63)		Demand Response Revenue Requirement.
Exhibit A-83 (HJM-64)		Karn Retention Revenue Requirement Comparison.

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 (Schedules E) exhibits. Company witnesses Aponte, Hubert W. Miller, and Rachel L. Barnes are sponsoring cost of service allocation, present and proposed revenue, and proposed tariff sheet (Schedule F) exhibits.

Q. Please summarize the key findings for the projected test year exhibits.

A. The exhibits demonstrate the following for the test year ending December 31,2021:

Jurisdictional	(000)
Rate Base	$11,844,757
Adjusted NOI	539,156
Overall Rate of Return	4.55%
Required Rate of Return	6.09%
Income Required	721,639
Income Deficiency (Sufficiency)	182,483
Revenue Multiplier	1.3391
Revenue Deficiency (Sufficiency)	244,357

The data for the above are presented on Exhibit A-11 (HJM-39), Schedule A-1, Revenue Deficiency (Sufficiency) for Test Year – December 2021.

Q. What inflation factors is the Company using in its presentation?

A. The Company is using inflation factors of 1.90% for 2019, 2.20% for 2020, and 2.20% for 2021, as forecasted by IHS Global Insight and reported in the July 2019 edition of its publication *U.S Economic Outlook*. IHS Global Insight is a leader in economic and financial analysis, forecasting, and market intelligence.

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 2021 projected test year to 2018 historical: Exhibit A-11 (HJM-41), Schedule A-3; Exhibit A-12 (HJM-43), Schedule B-1a; Exhibit A-12 (HJM-46), Schedule B-4; and Exhibit A-13 (HJM-62), Schedule C-14.

Q. Please explain Exhibit A-11 (HJM-40), 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 (HJM-41), Schedule A-3.

A. This exhibit presents the projected test year jurisdictional revenue deficiency for Consumers Energy of $244,357,000 (line 9, 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 in developing the projected test year revenue deficiency. Column (f) then displays the December 2021 rate base, income requirement, and revenue requirement.

Q. What are the major differences between the historical year and the projected test year results shown on Exhibit A-11 (HJM-41), Schedule A-3?

A. The comparison of historical and projected results in Exhibit A-11 (HJM-41), Schedule A-3, shows that rate base increases by 1,633,805,000(line 3) and the rate of return increases from 5.84% to 6.09% (line 4). In addition, the adjusted NOI (line 6) decreases by (73,050,000) when moving from the 2018 historical year to the projected test year.

Q. Please describe Exhibit A-12 (HJM-42), Schedule B-1.

A. Exhibit A-12 (HJM-42), Schedule B-1, is a summary presentation of the projected test year average rate base. The adjusted jurisdictional December 2019 average rate base is $11,844,757,000 as shown on line 7, column (d).

Q. Please describe Exhibit A-12 (HJM-43), Schedule B-1a.

A. Exhibit A-12 (HJM-43), Schedule B-1a, shows the development of the projected test year average rate base in an alternate presentation to Exhibit A-12 (HJM-43), Schedule B-1a. Line 3 shows the average rate base for the historical 2018 period. Lines 4 through 12 show the adjustments to the historical rate base necessary to develop the projected test year rate base. The adjustment to historical net plant (line 4) is related to projected capital expenditures for 2019, 2020 and 2021 as provided by Company witnesses Richard T. Blumenstock, Scott A. Hugo, Jeffrey D. Tolonen, Heather A. Breining, Steven Q. McLean, Karen M. Gaston, LaTina D. Saba, and Kyle P. Jones. Working capital is adjusted to reflect September 2019 balances (line 6). Working capital is adjusted for pension accounts (line 7) and Other Post-Employment Benefits ("OPEB") accounts (line 8) to reflect projected test year amounts supplied by Company witness Lora B. Christopher. Line 9 adjusts working capital for accrued taxes. Line 10 adjusts working capital for Cloud prepayments as supported by Company witness Tolonen. Finally, Line 11 adjusts working capital for PowerMiDrive. The projected test year jurisdictional rate base is shown on line 14, column (d) in the amount of $11,844,757,000.

Q. Please describe how the projected test year average plant and related amounts were developed.

A. Average electric plant and reserve balances for the December 2021 projected test year were developed by taking the average of the balances at December 31, 2020 and December 31, 2021. To accomplish this, actual December 2018 plant balances for Construction Work In Progress ("CWIP"), gross plant, and the accumulated provision for depreciation were used as the starting point. Capital expenditures (including Allowance for Funds Used During Construction ("AFUDC")) and plant additions were added for 2019, 2020 and 2021; followed by adjustments for expected retirements, depreciation expense, cost of removal, and the calculation of the ending balances for CWIP, plant, and the accumulated provision for depreciation.

Q. Please describe Exhibit A-12 (HJM-44), Schedule B-2.

A. Exhibit A-12 (HJM-44), Schedule B-2, shows the utility plant for the projected test year that was developed as described above. Line 4 shows total utility plant for the projected test year.

Q. Please describe Exhibit A-12 (HJM-45), Schedule B-3.

A. Exhibit A-12 (HJM-45), Schedule B-3, presents the projected depreciation reserve for the projected test year by functional group. The total on line 8 is carried forward to line 2 on Exhibit A-12 (HJM-42), Schedule B-1. The increase in the projected accumulated depreciation provision for the test year incorporates depreciation expense calculated using book depreciation rates included in Case No. U-17653. The calculated depreciation expense and associated accumulated depreciation presented also uses depreciation rates for the Ludington Hydro facility approved in Case No. U-16055 through the middle of January

2019. The depreciation expense calculation as presented in this case begins using the newly approved Ludington Hydro facility rates, as approved in Case No. U-18195, in the middle of January 2019 to coincide with the implementation of the use of the Case No. U-18195 depreciation rates.

Q. Please explain Exhibit A-12 (HJM-46), Schedule B-4.

A. Exhibit A-12 (HJM-46), Schedule B-4, develops the Company's proposed projected test year balance sheet working capital requirement. The starting point is the 13-month average historical December 2018 working capital shown in column (b), which is first adjusted to reflect the 13-month average ending September 2019 balances shown in column (d), the most current study practical for inclusion at the time of assembling the case. The September 2019 average balances are then adjusted to: (i) reflect changes to pension and OPEB balances based on projections sponsored by Company witness Christopher; (ii) reflect changes to accrued tax balances, (iii) reflect changes to Cloud prepayment balances sponsored by Company witness Tolonen, and (iv) reflect the inclusion of PowerMiDrive balance as supported in section III of this testimony. Details for the adjustments made to calculate a normalized working capital are shown on page 2 of the exhibit.

Q. Why did the Company use the balance sheet approach in determining the working capital requirement?

A. Use of the balance sheet method was mandated by the Commission in Case No. U-7350. The Commission, in Case No. U-15895, also required that this method be used to develop the allowance for working capital.

Q. Please describe Exhibit A-12 (HJM-48), Schedule B-5.

A. Exhibit A-12 (HJM-48), Schedule B-5, provides a summary of capital spending as supported by various Company witnesses. This exhibit provides capital spending for the bridge years and projected test year as well as the actual and projected spending during the previous rate case test year in Case No. U-20134.

Q. Based on your analyses, what is Consumers Energy's adjusted NOI for the projected test year?

A. The jurisdictional electric adjusted NOI for the projected test year is shown on line 20, column (d), of Exhibit A-13 (HJM-49), Schedule C-1. The total operating revenues on line 4 are netted against the total operating expenses on line 13 to arrive at NOI on line 14. From there, further adjustments are made on lines 15 through 18 utilizing normal ratemaking practices to arrive at the jurisdictional electric adjusted NOI on line 20 of $539,156,000.

Q. Please describe Exhibit A-13 (HJM-50), Schedule C-2.

A. Exhibit A-13 (HJM-50), Schedule C-2, shows the development of the revenue multiplier for the projected test year. The revenue multiplier is a factor that converts a utility's after-tax income deficiency (or sufficiency) into the required change in pre-tax revenue requirement. The Federal Income Tax ("FIT") rate is 21%, the Michigan Corporate Income Tax ("MCIT") rate is 5.310%, and the city income tax rate is 0.16%. The resulting revenue multiplier is 1.3391.

Q. Please explain the projected revenues shown on Exhibit A-13 (HJM-51), Schedule C-3.

A. Total projected revenues are shown on line 5. Lines 1, 2, and 4 of the exhibit present the sales, wholesale, and other electric revenues that are supported by Company witness Breuring.

Q. Please explain Exhibit A-13 (HJM-52), Schedule C-4.

A. This exhibit presents the projected power supply costs that are supported by Company witnesses Breuring.

Q. Please explain Exhibit A-13 (HJM-53), Schedule C-5.

A. Exhibit A-13 (HJM-53), Schedule C-5, presents the projected other O&M expense for the projected test year as compared to historical O&M expense. The amounts on lines 1 through 20 were provided by Company witnesses Blumenstock, Hugo, Christopher, Saba, Jones, McLean, Tolonen, Gaston, Chris A. Shellberg, and Amy M. Conrad and are supported in their respective direct testimony and exhibits.

Q. Please explain Exhibit A-13 (HJM-54), Schedule C-6.

A. Exhibit A-13 (HJM-54), Schedule C-6, presents the projected depreciation & amortization expense. Depreciation expense is calculated using book depreciation rates included in Case No. U-17653. The calculated depreciation expense and associated accumulated depreciation presented also uses depreciation rates for the Ludington Hydro facility approved in Case No. U-16055 through mid-January 2019. The depreciation expense calculation as presented in this case begins using the newly approved Ludington Hydro facility rates, as approved in Case No. U-18195, in in mid-January 2019 to coincide with the implementation of the Case No. U-18195 depreciation rates.

Q. Please explain Exhibit A-13 (HJM-55), Schedule C-7, through Exhibit A-13 (HJM-59), Schedule C-11.

A. These exhibits present the following: (i) projected general taxes; (ii) projected FITs; (iii) projected state income taxes; (iv) projected other (or local) taxes; and (v) projected AFUDC. The total from each schedule is carried forward to the Company's projected NOI presentation on Exhibit A-13 (HJM-49), Schedule C-1.

Q. Does the calculation of projected federal income tax, as provided in Exhibit A-13 (HJM-56), Schedule C-8, include a reduction for the amortization of excess deferred federal income taxes as ordered by the Commission in Case No. U-20309?

A. Yes. Lines 46 and 47 provide a reduction to federal income tax for the amortization of excess deferred income taxes, as ordered by the Commission in Case No. U-20309. Company witness Brian J. VanBlarcum explains the provisions of the Commission September 26, 2019 Order from Case No. U-20309 in his testimony and provides a calculation of the amortization in his Exhibit A-113 (BJV-2).

Q. Did the September 26, 2019 Order in Case No. U-20309 establish an electric credit intended to serve as a reduction in customer rates to reflect the amortization of excess deferred federal income taxes?

A. Yes. The Commission order provided for an electric credit to be in place until the establishment of new rates in the Company's next electric rate case.

Q. Should the electric credit established in Case No. U-20309 terminate when rates are reset in this electric rate case?

A. Yes. The amortization of the excess deferred federal income taxes has been built into the revenue requirement for this case and will be incorporated into base rates. As such, the electric credit established in Case No. U-20309 should terminate when rates are reset in this case.

Q. Please describe Exhibit A-13 (HJM-60), Schedule C-12.

A. Exhibit A-13 (HJM-60), Schedule C-12, shows the calculation of pro forma interest expense for the projected test year (and the corresponding change in FIT).

Q. Please describe Exhibit A-13 (HJM-61), Schedule C-13.

A. Exhibit A-13 (HJM-61), 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 (HJM-61), Schedule C-12, and Exhibit A-13 (HJM-62), Schedule C-13, included in the presentation?

A. The purpose of theses 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.

Q. Please explain Exhibit A-13 (HJM-62), Schedule C-14.

A. Exhibit A-13 (HJM-62), Schedule C-14, presents the reconciliation of the 2018 historic year NOI to the projected test year ending December 2021 NOI. The amounts within this schedule are taken from other exhibits in my presentation. The exhibit is laid out with revenues in columns (b) through (e), expenses in columns (f) through (m), and the resulting adjusted NOI in column (p). The exhibit begins with the historical year on line 1, then reflects normalizing adjustments on lines 2 through 14 and test year adjustments on lines 17 through 28. Total electric NOI for the projected test year is shown on line 30. The application of the jurisdictional factor shown on line 31 results in the jurisdictional electric NOI for the projected test year shown on line 32. In general, the revenues and expenses adjustments are shown with their accompanying tax impacts to arrive at adjusted NOI. Line 1 represents the 2018 historic year NOI in the amount of $736.7 million in column (p) ties to the historic NOI on line 17 of Exhibit A-3 (HJM-9), Schedule C-1.

Q. Please explain the normalizing adjustments on Schedule C-14.

A. The adjustments located on lines 2 through 14 are made to comply with prior Commission orders and follow traditional ratemaking adjustments to historical booked results such as: (i) removing regulatory disallowances; (ii) normalizing for unusual, one-time, or out-of-period items; (iii) bringing certain revenues and expenses "above the line;" (iv) adjusting historical revenues to reflect "normal" weather; and (v) performing related adjustments to income taxes. Additional adjustments include certain O&M expense normalizations to better align the historic test year with expected expense amounts in the projected test year. These adjustments are supported by Exhibit A-3 (HJM-20), Schedule C-12, through Exhibit A-3 (HJM-33), Schedule C-25. Compensation normalizations on line 2 are supported by Exhibit A-3 (HJM-20), Schedule C-12. Compensation adjustments are shown on line 2 and are supported by Exhibit A-3 (HJM-20). Dues and donations disallowances on line 3 are supported by Exhibit A-3 (HJM-21), Schedule C-13. Corporate Giving & Communications adjustments on line 4 are supported by Exhibit A-3 (HJM-23), Schedule C-15. Weather normalizations on line 5 are provided by witness Breuring and are supported by Exhibit A-3 (HJM-24), Schedule C-16. PSCR Adjustments on line 6 is supported by Exhibit A-3 (HJM-25), Schedule C-17. Line 7 normalizes expenses to increase revenue requirement for customer deposit interest and is supported by Exhibit A-3 (HJM-26), Schedule C-18. Lines 8 & 9 normalize other revenue and O&M expense to include jobwork revenue and expense, supported by Exhibit A-3 (HJM-27), Schedule

C-19, and Exhibit A-3 (HJM-28), Schedule C-20. Line 10 normalizes transmission depreciation expense, which is supported by Exhibit A-3 (HJM-30), Schedule C-22. Line 11 increases property tax expense for a property tax adjustment that is supported on Exhibit A-3 (HJM-31), Schedule C-23. Line 12 adjusts for surcharge revenue, expense, and amortization as supported by Exhibit A-3 (HJM-29) Schedule C-21. The pro forma income tax savings and interest synchronization on lines 12 and 13 are longstanding ratemaking conventions that are supported on Exhibit A-3 (HJM-32), Schedule C-24, and Exhibit A-3 (HJM-33), Schedule C-25, respectively.

The Adjusted Section A Operating Income of $616,904,000 on line 16, column (p) of Exhibit A-13 (HJM-62), Schedule C-14, ties to the Adjusted Operating Income on line 32 of Exhibit A-3 (HJM-9), Schedule C-1.

Q. How were the projected test year adjustments on Exhibit A-13 (HJM-62), Schedule C-14, developed?

A. These adjustments represent the movement from the normalized historical operating income to the projected test year NOI.

The adjustments on lines 17 through 28 are developed from my exhibits and supporting workpapers, and from the exhibits of other Company witnesses. The test year NOI on line 30 is the result of netting the test year adjustments on line 29 against the normalized historical operating income on line 16. The NOI – test year of $534,565,000 on line 30, column (p), ties to the total electric adjusted NOI on line 20 of Exhibit A-13 (HJM-49), Schedule C-1. The jurisdictional income – test year amount of $539,156,000 on line 32, column (p), ties to the jurisdictional electric adjusted NOI on line 20 of Exhibit A-13 (HJM-49), Schedule C-1.

Q. Please explain the test year adjustments made for the projected test year on Exhibit A-13 (HJM-62), Schedule C-14.

A. Lines 17 through 19 represent the changes in revenues when moving to the projected test year and are supported by Company witness Breuring. Line 20 represents an adjustment to power supply costs as shown on Exhibit A-13 (HJM-52), Schedule C-4, to align the projected test year PSCR expense with the projected test year PSCR revenues proposed by Company witness Breuring.

Line 21 represents an adjustment to Other O&M expense of $119,726,000 and is supported in the presentations of Company witnesses Blumenstock, Shellberg, Breuring, Hugo, Christopher, Conrad, Hall, Gaston, McLean, and Saba. The adjustments are summarized on Exhibit A-13 (HJM-53), Schedule C-5.

Line 22 represents the change in the book depreciation expense. The Company used the Commission approved depreciation rates along with the projected capital expenditures and assumed plant retirements, in the determination of this depreciation expense adjustment necessary to arrive at an appropriate level of book depreciation expense. Book depreciation expense was developed by applying the functional composite book depreciation rates to the average projected test year depreciable plant balances. The adjustment on line 22 increases depreciation expense from the historical period due to significant new investment.

Line 23 represents an adjustment to real and personal property taxes to the projected test year expense level as supported by Company witness VanBlarcum and shown on Exhibit A-13 (HJM-55), Schedule C-7.

Line 24 represents an adjustment to payroll and other general taxes to the projected test year level as shown on Exhibit A-13 (HJM-55), Schedule C-7.

Line 25 represents city income tax adjustments to the projected test year level city income tax expense as shown on Exhibit A-13 (HJM-58), Schedule C-10.

Line 26 reflects the impact of the state income taxes. State income tax expense is shown on Exhibit A-13 (HJM-57), Schedule C-9.

Line 27 represents an adjustment to AFUDC to the projected test year level. This amount is shown on Exhibit A-13 (HJM-59), Schedule C-11. AFUDC is an accounting convention that recognizes the costs, both interest and equity, of financing certain construction projects. The recognition is through the transfer of interest and equity cost from the income statement to CWIP on the balance sheet. The interest and equity costs are capitalized in the same manner as construction labor and material costs when the project is closed to plant-in-service. The criteria for applying AFUDC to a construction project require on-site construction activities of more than six months duration and an estimated plant cost (excluding AFUDC) in excess of $50,000. AFUDC charged to projects addressing compliance with environmental clean air requirements are not included in this ratemaking adjustment, which is consistent with the Commission's ratemaking treatment.

Line 28 represents the FIT adjustments which result from the other changes in revenue and expense levels for the projected test year. Also reflected are the differences between the FIT expense calculated at the current federal statutory rate and the actual total income tax expense.

Q. Please describe Exhibit A-82 (HJM-63).

A. Exhibit A-82 (HJM-63) is a two-page exhibit that calculates the 2021 revenue requirement for DR programs as included in this case. The first page of the exhibit calculates the 2021 revenue requirement for the residential demand response programs and the second page of the exhibit calculates the 2021 revenue requirement for the commercial and industrial DR program. The intent of this exhibit is to establish the revenue requirement included in rates approved in this case. Should the Commission adjust the capital or O&M spending requested for DR, it would be necessary to update this exhibit to reflect those changes. The Company requests that the final order in this case specifically indicate the DR revenue requirement approved in order to simplify future DR reconciliation proceedings.

Q. Please describe Exhibit A-83 (HJM-64).

A. Exhibit A-83 (HJM-64) provides the revenue requirement of including Karn Units 1 and 2 retention costs as O&M expense for 2021 and the revenue requirement if Karn Units 1 and 2 retention costs were recorded as a regulatory asset and amortized over the remaining life of the remaining coal plants. Company witness Hugo explains the Karn Units 1 and 2 retention program and Company witness Daniel L. Harry provides support for the Company's request to record the Karn Units 1 and 2 retention costs as a regulatory asset.

Q. Does the revenue deficiency, as filed in this case, include the 2021 O&M expense related to Karn Units 1 and 2 retention?

A. Yes. The revenue deficiency, as filed in this case, includes 2021 O&M expense related to Karn Units 1 and 2 retention.

Q. Line 8 of Exhibit A-83 (HJM-64) shows a difference in revenue requirement of $5,485,000. What does this represent?

A. The $5,485,000 difference in revenue requirement represents the reduction in the as filed revenue deficiency that would be achieved with the approval of the Company's proposed treatment of Karn Units 1 and 2 retention costs that would record the costs as a regulatory asset to be amortized over the life of the remaining coal plants.

III. PowerMIDrive PILOT PROGRAM

Q. Has the Commission approved deferred accounting treatment for the PowerMIDrive program?

A. In case No. U-20134, the Commission approved deferred accounting for expenditures associated with the PowerMIDrive Pilot Program. The approach adopted by the Commission envisioned a prudency 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 at the authorized rate of return.

Q. Are you sponsoring any exhibits related to the PowerMIDrive pilot program in this case?

A. Yes. The following exhibit is presented in support of the program:

Exhibit A-84 (HJM-65) PowerMIDrive

Q. Please describe Exhibit A-84 (HJM-65).

A. Exhibit A-84 (HJM-65) provides the calculation of the projected test year amortization expense and the projected test year average deferred balance associated with the Program.

Q. Please explain line 1 of Exhibit A-84 (HJM-65).

A. Line 1 provides the actual 2019 deferred expenditures for the Program through October and forecasted amounts for November and December. The Program expenditures are supported by Company witness Sarah R. Nielsen.

Q. Why are you including projected expenditures for November and December?

A. November and December actuals were not available at the time this rate case was assembled. I have included projected expenditures for these months in order to reflect an estimate of 2019 actual expenditures. Actual expenditures for all of 2019 will be made available for the MPSC Staff's ("Staff") review and the Company requests that 2019 expenditures be reviewed and that the applicable amortization expense and rate base amounts be included for rate recovery.

Q. Please describe the remainder of Exhibit A-84 (HJM-65).

A. Lines 2 and 3 show the estimated amortization expense for 2020 and 2021. The 2021 amortization expense of $129,000 has been included in the projected amortization expense on Exhibit A-13 (HJM-54). Line 4 shows the calculation of the average rate base amount for 2021 associated with the 2019 program expenditures. The $453,000 average rate base amount for 2021 has been included in the projected working capital on Exhibit A-12 (HJM-47).

IV. ELECTRIC RATE CASE DEFERRAL

Q. Did the settlement agreement approved by the Commission in Case No. U-20134 provide for a deferral of the revenue requirement of certain distribution capital spending above certain amounts?

A. Yes. Specifically, the settlement agreement allowed for deferred accounting for the return on, return of, and property taxes associated with actual 2019 capital spending above the following amounts: $94,000,000 for new business, $87,000,000 for reactive demand failures, and $24,000,000 for asset relocation.

Q. Are you sponsoring any exhibits related to the electric rate case deferral in this case?

A. Yes. The following exhibit is presented in support of the electric rate case deferral:

Exhibit A-85 (HJM-66)	Electric Rate Case Deferral

Q. Did the Company have actual 2019 capital spending above the amounts included in the settlement agreement for new business, reactive demand failures, and asset relocation?

A. Yes. As provided on page one of Exhibit A-85 (HJM-66), the Company had actual 2019 capital spending above the amounts included in the settlement for all three of the referenced capital spending programs.

Q. Have you calculated the return on, return of, and property tax related to the capital spending above the amounts included in the settlement agreement for new business, reactive demand failures, and asset relocation?

A. Yes. Page 2 of Exhibit A-85 (HJM-66) provides the calculation of the return on, return of, and property tax related to the capital spending above amounts included in the settlement agreement for new business, reactive demand failures, and asset relocation.

Q. Line 12 of page 2 of Exhibit A-85 (HJM-66) provides a total 2019 revenue requirement of $6,300,000. Please explain.

A. The $6,300,000 total 2019 revenue requirement includes the return on; depreciation expense, which is also known as the return of; and property tax expense attributable to the capital spending above the amounts included in the settlement agreement. These amounts were calculated to represent the increase in revenue requirement that would have been built into the settlement agreement if the additional capital spending would have been included.

Q. Line 13 of page 2 of Exhibit A-85 (HJM-66) adds the 2020 deferral to the 2019 revenue requirement on line 12 to arrive at the line 14 total electric rate case deferral of $12,600,000. What does the 2020 deferral represent and why is it added to the 2019 revenue requirement when calculating the total deferral?

A. The 2020 deferral on line 13 represents the amount that would have been in rates in 2020 if the capital spending above the amounts included in the settlement agreement would have been included in the settled rates established in Case No. U-20134.

Q. Why is it appropriate to also include the foregone 2020 collection of the 2019 revenue requirement in the total deferral?

A. The settlement agreement in Case No. U-20134 also provides that the Company would not file another electric rate case until January 1, 2020. Given this, the earliest the Company could have reset rates to incorporate the additional distribution capital spending in base rates would have been November of 2020. In addition, the Company is filing this rate case with a projected test year beginning January of 2021 so the Company will not be adjusting base rates to incorporate the revenue requirement of the additional capital spending in base rates until 2021. The 2020 deferral is intended to acknowledge that had the rates established in the settlement considered the additional capital spending, the 2019 revenue requirement would have also been in rates in 2020.

Q. Is the actual 2020 revenue requirement for the capital spending above rates the same as the actual 2019 revenue requirement?

A. No. The 2019 investment was in service for the entirety of 2020; therefore, the 2020 revenue requirement for the capital spending above rates would be higher than the 2019 revenue requirement. The 2020 revenue requirement excludes the test-year averaging of the rate base items when calculating the return. The depreciation expense is doubled reflecting the removal of the effects of the half-year convention that provides a half years of depreciation expense in the first year an asset is in service.

Q. Is the Company requesting deferral and recovery of the 2020 revenue requirement for the capital spending above amounts included in the settlement agreement?

A. No. The Company is requesting that the 2020 deferral match the 2019 deferral thus providing amounts that would have been in rates for 2019 and 2020 had the settlement agreement considered the additional capital spending in arriving at the rate relief provided for 2019.

Q. Was the Company able to record revenue for the full return associated with the capital spending above amounts included in the settlement agreement?

A. No. Per accounting guidance, the Company was not able to record revenue associated with the return on equity portion of the cost of capital. Revenue related to the return on equity will not be recorded until collected from customers. The regulatory asset account related to this deferral includes the return on equity but there is a contra regulatory asset account that offsets the regulatory asset by the amount related to the return on equity. The regulatory asset account houses the total revenue requirement and will continue to be increased through 2020 to arrive at the $12,600,000 total deferral that should be approved for recovery.

Q. How does the Company propose to collect the total deferral from customers?

A. The Company proposes that a 12-month charge be established to collect the $12,600,000 total deferral. The Company further proposes that the charge be implemented on January 1, 2021 and terminated after 12 months. See the testimony of Company witnesses Aponte and Miller for the allocation and design of the charge.

Q. Is the $12,600,000 total deferral in the revenue deficiency presented in this case?

A. No. Should recovery of the deferral be included in base rates, instead of the proposed separate charge, the revenue deficiency would need to be increased by $12,600,000.

V. <u>FINANCIAL COMPENSATION MECHANISM</u>

Q. Are you sponsoring any exhibits related to the FCM in this case?

A. Yes. The following exhibit is presented in support of the FCM:

Exhibit A-88 (HJM-69)	Financial Compensation Mechanism - Timeline.

Q. Please describe the FCM.

A. As described by Company witness Keith G. Troyer, the FCM was approved in Case No. U-20165. The FCM allows the Company to collect the weighted average cost of capital applied to the payments for eligible Purchased Power Agreements ("PPA"), also referred to as the FCM amount.

Q. Does the Company have eligible PPA's and associated FCM amounts?

A. Yes, Company witness Troyer calculates an FCM amount of $3,031,000 for the years 2019 through 2021.

Q. Did the settlement agreement approved in Case No. U-20165 specify how the approved FCM should be collected from customers?

A. No. in the approved settlement agreement in Case No. U-20165 did not specify how the approved FCM should be collected from customers. The settlement agreement, provides that the method of cost recovery for the FCM will be determined in the Company's next electric rate case, which is the present case before the Commission. The remainder of this section of my testimony will describe the Company's proposed method of cost recovery for the FCM.

Q. Please summarize the Company's proposed method for recovering the FCM amounts.

A. The Company proposes that the initial FCM amount of $3,031,000 be collected through a surcharge beginning January 1, 2021. Further, the Company proposes that a case be filed by March 31, 2022 that would reconcile actual surcharge collections during 2021 to the actual FCM amount through 2021. The proposed case filing would also establish the surcharge to be billed beginning July 1, 2022, designed to collect the 2022 FCM as well as any difference between the actual surcharge billed during 2021 and the actual FCM amount through 2021. Similar filings would be made by March 31st each year, reconciling the prior year FCM and establishing the current year surcharge. Given the limited nature of these filings and for reasons discussed further in this testimony, the Company requests that these annual filings be conducted under a 90-day case schedule.

Q. Please explain why the Company has proposed to make its FCM filings by March 31st of each year.

A. The Company is statutorily required to reconcile its actual power supply costs by March 31st of each year. As part of its power supply cost reconciliation filings, the Company presents the actual PPA payments made to PPA counterparties in the subsequent year. While the Company is proposing to file its annual FCM filing in a separate proceeding from the Company's power supply cost reconciliation proceeding, the Company's FCM filing will utilize the actual PPA payments presented in the Company's power supply cost reconciliation proceeding to reconcile the FCM amounts collected from customers in the time period subject to reconciliation.

Q. Exhibit A-88 (HJM-69) provides a timeline and details supporting the Company's proposed method for recovering the FCM. Please describe line 1 of this exhibit.

A. Line 1 of Exhibit A-88 (HJM-69) indicates that on January 1, 2021 the first FCM surcharge would be implemented and would be designed to collect the 2019 through 2021 FCM amounts over 12 months. Company witness Aponte supports the allocation of the FCM amount and Company witness Miller presents the design of the surcharge.

Q. What does line 2 of Exhibit A-88 (HJM-69) illustrate?

A. Line 2 of Exhibit A-88 (HJM-69) illustrates the filing of the first FCM case. The purpose of the annual FCM filing is to reconcile FCM surcharge amounts billed with actual FCM amounts and to establish the surcharge to be implemented at the conclusion of the FCM case.

Q. What will be reconciled in the first annual FCM case?

A. The first annual FCM case filed by March 31, 2022 will reconcile billed FCM surcharge amounts during calendar year 2021 with actual FCM amounts for the years 2019 through 2021.

Q. The first annual FCM case also establishes a new FCM surcharge. How is the new FCM surcharge amount calculated?

A. The new FCM surcharge amount to be implemented on July 1, 2022 is calculated by starting with the actual FCM amount for the years 2019 through 2021 and subtracting actual surcharge amounts billed during calendar year 2021, and adding the projected FCM amount for 2022.

Q. Will the surcharge implemented on January 1, 2021 remain in place until the FCM surcharge is adjusted for the outcome of the first FCM case?

A. Yes. The surcharge implemented on January 1, 2021 will remain in place until adjusted by the outcome of the first FCM case and any amounts billed between January 1, 2022 and July 1, 2022 will become part of the reconciliation of the actual 2022 billed FCM surcharge to the actual 2022 FCM amount.

Q. Line 3 of Exhibit A-88 (HJM-69) shows an adjustment to the FCM surcharge implemented on July 1, 2022. Please explain.

A. The Company requests that the annual FCM cases receive an order within 90 days of filing. The FCM cases will be filed by March 31st of each year and would conclude and allow for adjustments to the FCM surcharge by July 1st of each year.

Q. Line 4 of Exhibit A-88 (HJM-69) illustrates the details of the second filed FCM case. Please describe the second FCM case.

A. The second FCM case will be filed by March 31, 2023 and will reconcile actual FCM surcharge amounts billed in 2022 to the actual 2022 FCM amount. The second FCM case will also establish the new FMC surcharge to be implemented July 1, of 2023.

Q. Will the FCM cases continue annually after the March 31, 2023 filing?

A. Yes. The FCM cases will continue annually following the same format as the March 31, 2023 filing.

Q. Why is the Company proposing to collect the FCM amounts through a surcharge?

A. Collecting the FCM amounts through a surcharge with the reconciliation process designed as described in this testimony will allow the Company to record the FCM amounts in the year earned and will provide interested parties an opportunity to easily review the collections for FCM amounts as compared to actual FCM amounts.

Q. How is the Company's ability to record the FCM amounts in the year earned impacted by the process approved for collection?

A. As explained by Company witness Harry, there needs to be a collection process in place that will ensure revenues will be collected within 24 months of when they are recorded in order to record them in the period earned. Approval of the Company's proposed method of recovering the FCM amounts would allow for the collection of the FCM amounts within 24 months. In addition, the Company has proposed the FCM amounts be collected through a surcharge with annual reconciliations instead of building the FCM amount into base rates because annual rate case filings are not guaranteed, and this may prevent the Company from recording the FCM revenue in the period earned.

Q. What is the significance of recording the FCM amounts in the period earned?

A. Company witness Harry explains that it is important to record the FCM revenue in the same period that the related PPA costs are incurred to have the financial statements reflect the true economics of the program.

VI. <u>CONSERVATION VOLTAGE REDUCTION</u>

Q. Is the Company proposing to establish an incentive as part of its conservation voltage reduction ("CVR") program?

A. Yes. Company witness Michael J. Delaney supports an incentive as part of the CVR program.

Q. How does the Company propose to collect the CVR incentive?

A. The Company proposes to collect the CVR incentive through a surcharge. Company witness Delaney supports the incentive amount for 2021. Company witness Aponte provides the allocation of this incentive and Company witness Miller presents the design of the surcharge.

Q. How does the Company propose to collect future CVR incentives?

A. The Company proposes that future CVR incentives be addressed in an annual filing. The first annual filing would be made by March 31, 2022 and would provide the actual billed CVR surcharge during 2021 to be reconciled with the actual CVR incentive for 2021. The CVR surcharge would be adjusted as a result of this filing and would be calculated by starting with the actual 2021 incentive and then subtracting the actual CVR surcharge billed in 2021 and adding the projected CVR incentive for calendar year 2022. The CVR incentive would continue to be addressed in the same fashion in each annual filing.

Q. Please explain how the actual CVR incentive for the prior year will be calculated as part of each annual filing.

A. The actual CVR incentive will be calculated by modifying the CVR incentive projections to reflect actual energy and capacity savings that are realized by customers. The items that will be adjusted to reflect actual savings are voltage reduction, loss reduction, and zonal resource credits.

For example, on Exhibit A-58 (MJD-1), the 2021 calculation of customer savings shows a benefit of $5.5 million. The shared savings percentage of 15% is then applied to this amount to arrive at the $0.8 million incentive. At the time of reconciliation, this calculation would be adjusted to update the voltage reduction, loss reduction, and zonal resource credits used in the calculation to arrive at the actual CVR incentive for the 2021.

Q. Does the Company have any additional requests related to the annual CVR filings?

A. Yes. The Company requests that the annual filings be conducted under a 90-day case schedule given the limited nature of the filings.

Q. Why is the Company proposing to collect the CVR incentive through a surcharge?

A. Collecting the CVR incentive through a surcharge with the reconciliation process designed as described in this testimony will allow the Company to record the CVR incentive in the year earned and will provide interested parties an opportunity to easily review the collections for the CVR inventive as compared to the actual CVR incentive.

Q. How is the Company's ability to record the CVR incentive amounts in the year earned impacted by the process approved for collection?

A. As explained by Company witness Harry, there needs to be a collection process in place that will ensure revenues will be collected within 24 months of when they are recorded in order to record them in the period earned. Approval of the Company's proposed method of recovering the CVR incentive would allow for the collection of the CVR incentive within 24 months. In addition, the Company has proposed the CVR incentive be collected through a surcharge with annual reconciliations instead of building the CVR amount into base rates because annual rate case filings while likely are not certain and this may prevent the Company from recording the CVR incentive revenue in the period earned.

Q. What is the significance of recording the CVR incentives in the period earned?

A. It is important to record the CVR incentives in the same period that the related customer savings occur to have the financial statements reflect the true economics of the program.

VII. <u>HSC CONTRACT</u>

Q. Are you sponsoring any exhibits related to the HSC contract in this case?

A. Yes. The following exhibits are presented in support of the HSC contract:

Exhibit A-86 (HJM-67)	HSC Contract Levelized Revenue Requirement - Capacity
Exhibit A-87 (HJM-68)	HSC Contract – Distribution Charge

Q. Please summarize your exhibits filed in support of the HSC contract.

A. Page 1 of Exhibit A-86 (HJM-67) provides the levelized revenue requirement of the designated resource. This levelized revenue requirement is used by Company witness Michael P. Kelly to calculate the capacity charge for the HSC contract. Page 2 of Exhibit A-86 (HJM-67) shows the calculation of rate base and depreciation expense used on page 1 of the exhibit. Exhibit A-87 (HJM-68) provides the calculation of the distribution charge for the HSC contract. Assumptions and projections used in these exhibits represent amounts in effect or projections assumed at the time the HSC contract was executed.

Q. Page 1 of Exhibit A-86 (HJM-67) provides the calculation of the levelized revenue requirement of the designated resource in support of the capacity charge. What is the designated resource?

A. As explained by Company witness Kelly, the designated resource is the Company-owned natural gas combined cycle Zeeland Generating Station ("Zeeland CCGT").

Q. How have rate base and operations expenses related to the Zeeland CCGT been included in the revenue requirement filed as part of this case?

A. All rate base and operations expense related to the Zeeland CCGT are included in the calculation of the revenue requirement, as presented in this case. The HSC contract revenues, as calculated by Company witness Kelly, are then included as other revenue acting as an offset to the amounts included in the revenue requirement for Zeeland CCGT rate base and operating expense.

Q. Please describe how the annual revenue requirement of the Zeeland CCGT is calculated as provided on line 11 of page 1 of Exhibit A-86 (HJM-67).

A. The annual revenue requirement is calculated by taking the sum of the return on rate base, depreciation expense on the Zeeland CCGT, amortization expense related to the Zeeland acquisition adjustment allocated to the Zeeland CCGT, property tax expense, property insurance expense, gas transportation costs, overheads, and fixed operations and maintenance expense for the Zeeland CCGT.

Q. Please describe the calculation of the return on rate base as provided on line 3 of page 1 of Exhibit A-86 (HJM-67).

A. Line 3 of page 1 of Exhibit A-86 (HJM-67) provides the Zeeland CCGT return on rate base by year from 2021 through 2041. Company witness Kelly explains that this is the duration of the HSC contract. The return on rate base is calculated by multiplying rate base by the pretax cost of capital. Line 2 of the exhibit provides the pretax cost of capital of 7.40% representing the pretax cost of capital from the Company's last electric rate case, Case No. U-20134. Line 1 provides the average rate base by year as calculated on line 10 of page 2 of Exhibit A-86 (HJM-67).

Q. Please summarize how annual rate base amounts have been calculated on page 2 of Exhibit A-86 (HJM-67).

A. The calculation of rate base by year begins with actual 2018 year-end balances in column (a) of page 2 of Exhibit A-86 (HJM-67). 2018 year-end net plant as shown on line 9 of column (a) includes year end balances allocated to the Zeeland CCGT for plant in service, Zeeland's acquisition adjustment, accumulated depreciation less cost of removal, cost or removal collected net of cost of removal spent, accumulated amortization of the acquisition adjustment, and land balances. The total of these items provides the 2018 year-end rate base for the Zeeland CCGT. Rate base amounts are then projected out through 2020 to create a starting rate base amount for the beginning of the HSC contract. These projections include forecasted capital spending for 2019 and 2020 and utilize currently approved depreciation rates in calculating depreciation expense and accumulated depreciation for the assets. Starting in 2021 the rate base calculation continues to include projected annual capital spending related to the Zeeland CCGT and incorporates depreciation expense designed to recover the starting point rate base at the beginning of the contract plus all projected capital spending during the contract and decommissioning costs. The intent is to have the revenue requirements used in building the contract capacity charge be sufficient to cover the full cost of the Zeeland CCGT by the end of the contract.

Q. Line 4 of page 1 of Exhibit A-86 (HJM-67) provides the depreciation expense as included in the calculation of the annual revenue requirement for the Zeeland CCGT. Please explain.

A. The annual depreciation expense for the Zeeland CCGT provides for the collection of the remaining net book value of the Zeeland CCGT, projected cost of removal dollars spent through 2041, and anticipated decommissioning costs.

Q. Line 5 of page 1 of Exhibit A-86 (HJM-67) provides amortization expense. Please explain.

A. The annual amortization expense on Line 4 of page 1 of Exhibit A-86 (HJM-67) provides for the collection of the remaining balance of the Zeeland acquisition adjustment allocated to the Zeeland CCGT.

Q. Please describe Lines 9 and 10 of page 1 of Exhibit A-86 (HJM-67).

A. Lines 9 and 10 of page 1 of Exhibit A-86 (HJM-67) provides overhead costs and fixed O&M for the Zeeland CCGT for inclusion in the annual revenue requirement calculation for the Zeeland CCGT. Overheads represent administrative and general expenses allocated to the Zeeland CCGT. Fixed O&M expense consists of projected annual O&M expense designated as fixed O&M for inclusion in the capacity charge calculation. Variable O&M expense is included in the calculation of total contract revenues, as provided by Company witness Kelly.

Q. What is the NPV of the annual revenue requirement for the Zeeland CCGT?

A. Line 12 of page 1 of Exhibit A-86 (HJM-67) provides the Net Present Value ("NPV") of the annual revenue requirements for the Zeeland CCGT. The $656,557,000 NPV of the annual revenue requirements is the amount that would need to be paid in 2021 to support the capacity related revenue requirements of the Zeeland CCGT for the full duration of the HSC contract.

Q. Line 13 of page 1 of Exhibit A-86 (HJM-67) includes the levelized revenue requirement. Please explain.

A. The levelized revenue requirement converts the NPV of the annual revenue requirements into a levelized annual revenue requirement. This levelized annual revenue requirement is used by Company witness Kelly to calculate the capacity charge for the HSC calculation.

Q. How is the Company proposing to establish the distribution charges for the HSC contract?

A. PA 348 of 2018 requires that the electric utility recover its direct costs to provide transmission and distribution service to the industrial customer based on the dedicated distribution service costs and transmission service costs incurred specifically to serve the industrial customer, as approved by the Commission. The Long-Term Industrial Load Retention Rate ("LTIRR") tariff, which is included in Company witness Barnes' Exhibit A-16 (RLB-2), Schedule F-5, proposes that the monthly distribution charge be based on the dedicated distribution facilities in place to serve the customer, consistent with the statute. As a result, I determined a levelized revenue requirement over the life of the contract associated with recovering the costs of the distribution investments that serve the customer, as well as O&M and overheads that will be required to provide distribution service over the life of the contract.

Q. On what basis were the revenue requirements for distribution service determined?

A. The distribution service revenue requirements are based on 1) recovery of the investment in distribution facilities that serve the customer, 2) the O&M expense to maintain the facilities and 3) an appropriate share of overheads.

Q. How were these amounts calculated?

A. I started with the original cost of the distribution facilities that were put in place to serve the customer. I applied the Company's Pretax Cost of Capital to applicable rate base amounts to calculate the return on rate base and added that to depreciation, property tax, and insurance expense to determine annual revenue requirements through the life of the contract.

Q. How were the O&M and overheads determined?

A. The O&M expense and overheads were based on the equivalent O&M and overhead rates that are applicable to the distribution investment for General Primary Demand ("GPD") customers at the time the contract was executed. GPD is the rate schedule the customer would be served on, if this contract were not in place.

Q. Why is the original cost of the distribution investment used to determine the distribution charge?

A. The Company is proposing to use the original costs of investments, which avoids the need to use the current net book value and then estimate the additional incremental investment to be made over the life of the contract. As discussed in the testimony of Company witness Kelly, the customer has an existing facilities agreement for distribution that survives the special contact proposed in this case, and the facilities agreement specifies the cost responsibility of the parties for required future investment in distribution facilities.

Q. How did the Company determine the fixed monthly charge for distribution service?

A. As shown on Exhibit A-87 (HJM-68), I calculated the annual revenue requirements for distribution service through the life of the contract, or through year 2041, as shown in line 8. From that I determine a levelized annual revenue requirement shown in line 10, and a monthly revenue requirement on line 11, of $67,443. This is the amount proposed as the customer's fixed monthly distribution charge through the life of the contract.

VIII. AMI BUSINESS CASE FILING REQUIREMENT

Q. Has the Company complied with the requirement ordered in Case No. U-18322 to continue providing AMI business case analysis as part of its electric rate case application?

A. Yes. A business case summary is provided in Exhibit A-89 (HJM-70).

Q. Did the settlement agreement in the Company's last electric rate case, Case No. U-20134, address the Company's request to stop filing AMI business cases with each rate case filing?

A. No. Case No. U-20134 settlement agreement did not address the Company's request to conclude the obligation regarding AMI business case exhibits in electric rate case filings.

Q. Please describe the original use of this business case information.

A. Similar business case information was utilized to support the Company's investments in the AMI metering technology and system enhancements in Case Nos. U-17087, U-17735, U-17990, and U-18322.

Q. Was the implementation of AMI completed during 2017?

A. Yes. Meter upgrades began in August 2012 and concluded during the last quarter of 2017. In addition to the upgrade of metering technology, AMI systems development work has resulted in the implementation of several enhancements during that time, and the development of those systems has also concluded in 2017. The Company does not anticipate that future updates to the business case will be necessary, and respectfully requests the Commission to find that the update provided in this case conclude the Company's obligation to continue supporting business case updates related to investments in AMI.

Q. Please discuss the overall results of the cost/benefit analysis as summarized in Exhibit A-89 (HJM-70), Summary of AMI Business Case Costs and Benefits 2007 through 2032.

A. The Company's business case for Smart Grid ("SG")/AMI included both costs and benefits for both electric only and electric/gas combination customers to arrive at an estimation of the NPV of revenue requirements associated with the AMI investment. The revisions made in this case to the cost/benefit analysis changed the business case NPV of net savings in revenue requirements from $93.9 million in Case No. U-20134 to $160.5 million, an improvement of $66.6 million. The details of the $160.5 million NPV calculation are provided in Exhibit A-89 (HJM-70), page 5. A similar calculation of the present value of electric customer net savings in revenue requirements of $147.7 million is provided in Exhibit A-89 (HJM-70), page 6.

The cost/benefit analysis revisions that caused the business case NPV to change since the scenario filed in Case No. U-20134 are summarized as follows:

- Costs and benefits associated with customer engagement programs targeting savings in overall energy and peak demand capacity costs reflect a net decrease in NPV of $32.9 million from the prior cost/benefit analysis reflecting numerous changes, including:
    - revised timing for customer enrollments in Load Control and Dynamic Peak Pricing programs;

  - enrollment timing revisions reflect opportunities for the Company to engage business customers in demand response programs in the near term that also provide benefits to customers;
  - business customer programs are not included in the AMI cost/benefit analysis, resulting in an overall reduction of benefits attributed to AMI; and
  - elimination of initial estimates of costs and benefits associated with the Company's Case No. U-20134 proposed implementation of a Universal Peak Rebate offering, which was not approved for implementation in that proceeding;

- Program revenue requirements were reduced as a result of updating the cost/benefit analysis with the weighted average cost of capital proposed by Company witness Bleckman. Updating the cost of capital also reduced the NPV discount factors for future years in the cost/benefit model. Changing the pre-tax weighted average cost of capital from 7.87% to 7.63% increased the NPV of revenue requirement savings by $25.1 million; and
- Finally, in order to reflect the difference in timing between rate cases, the NPV calculation was adjusted so that all future net revenue requirements were discounted back to the beginning of 2021. The cost/benefit analysis provided in Case No. U-20134 discounted net revenue requirements back to the beginning of 2019. Making this change increased the calculated NPV of revenue requirement savings by $74.41 million.

In summary, the cost/benefit analysis provided in Exhibit A-89 (HJM-70) fulfills the requirement to provide an updated analysis and confirms that the Company's AMI investment continues to deliver additional benefits to customers as new AMI-enabled programs are implemented.

Q. What is the Company's recommendation regarding future updates to AMI cost/benefit analyses?

A. Consumers Energy requests that the requirement to provide an updated cost/benefit analysis be discontinued. The resources required to complete the update are better directed toward other initiatives.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697

DIRECT TESTIMONY

OF

SARAH R. NIELSEN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Sarah R. Nielsen, 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 Corporate Strategy.

Q. Please describe your educational background and work experience prior to Consumers Energy.

A. I received a bachelor's degree in biology from the University of Dayton, a Master of Business Administration degree from the Yale School of Management, and a master's degree in Environmental Science from the Yale School of Forestry & Environmental Studies.

I served as a Medical Service officer in the U.S. Army on active duty from 2006 to 2011, deploying in support of Operation Iraqi Freedom from 2008 to 2009. In this role, I served as the second-in-command Executive Officer for a 76-person medical company, directly responsible for 26 soldiers and maintenance of medical and combat equipment valued at over $14 million. I also served in the Connecticut National Guard from 2011 to 2013. From 2014 to 2017, I worked as a management consultant for Innosight, a consulting firm based out of Boston. In this position I managed teams of three to five people and managed relationships with clients from Fortune 500 companies, analyzing industry data and developing long-term growth strategies and execution plans.

Q. Please describe your work experience at Consumers Energy.

A. In 2017, I joined Consumers Energy as a Manager in the Corporate Strategy department. In this position, I was responsible for developing long-term strategies for the Company. This included in-depth research and analysis of: (i) energy sector trends and future business environment implications; (ii) program development and implementation; and (iii) external stakeholder management in the regulation, policy, advocacy, academic, and private sectors. In addition, I was the lead support for the development of the Company's infrastructure and grid management pilot, the PowerMIDrive Program ("PowerMIDrive"), approved by the Michigan Public Service Commission ("MPSC" or the "Commission") in 2018.

In 2018, I was promoted to Director of Corporate Strategy, which increased my responsibilities to include synchronizing long-term Company financial planning with Company strategies for our electric, gas, and retail businesses. I also assisted Edison Electric Institute, an association that represents and provides leadership, strategic business intelligence, and essential conferences and forums to all U.S. investor-owned electric companies, in solving electric transportation challenges across the electric industry. In 2020, I was promoted to Executive Director of Demand-Side Management.

Q. What are your responsibilities as Executive Director of Demand-Side Management?

A. In this role, I manage four programs: electric vehicles ("EVs"), voluntary green pricing, demand response, and summer peak pricing. For each program, I am responsible for setting the Company's strategy, collaborating with stakeholders, and managing the teams to ensure that the organization meets the Company's business needs and delivers a world-class customer experience.

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

A. There are two purposes to my direct testimony. First, I will outline and support Consumers Energy's proposal for a three-year PowerMIFleet Pilot Foundational Infrastructure Program ("PowerMIFleet," the "Pilot" or the "Program") to support grid management in light of the potential for growth in the EV market in the Company's electric service territory, with a focus on customers wishing to electrify their fleet vehicles. For the purpose of this document, the term EV will be used to describe electric vehicles, including plug-in hybrid electric vehicles and fully battery electric vehicles ("BEV").

The second purpose of my direct testimony is to report on the program costs for PowerMIDrive in its first year of operation. The costs are actuals for January through October 2019, and forecasts for November through December 2019.

Q. How is the remainder of your direct testimony organized?

A. The remainder of the direct testimony is organized as follows:

I. Support for Utility Investment in the Program

II. Pilot Program Proposal: PowerMIFleet

III. Request to Treat Costs as a Regulatory Asset

IV. Strategic Fit and Stakeholder Collaboration

V. PowerMIDrive Costs

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-90 (SRN-1)	Fleet EV Benefit Analysis for Consumers Energy Territory;
Exhibit A-91 (SRN-2)	PowerMIDrive Costs; and
Exhibit A-92 (SRN-3)	References Summary.

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

A. Yes.

I. Support for Utility Investment in the PowerMIFleet Program

A. Fleet EV Market Status, Benefits, and Challenges

Q. Why is the Company focusing on electric fleet vehicles at this time?

A. The number of electric fleet vehicles on U.S. roads is projected to grow rapidly in the near future due to the following three evolving factors and realities:

- Vehicle manufacturer commitments/vehicle availability is on the rise: Until recently, EV fleet vehicles were not in demand and, therefore, the number of commercially-available EV fleet vehicles was small in scale. Now, however, transit buses and school buses are growing in popularity for use by municipalities, and the numbers of such vehicles scheduled to become available for purchase in 2020 and beyond is also growing to meet those demands;

- Battery costs are driving down total cost of ownership: EV retail prices are generally higher than internal combustion engine ("ICE") models which has, historically, made ICE vehicles more attractive to buyers. As the use of EVs has grown in recent years, however, battery cost, the largest EV cost driver, has been trending downward, making those upfront costs that impact the purchase of an EV more comparable to that of the traditional ICE; and

- Emission regulations/concerns are and will continue to impact EV use and ownership choices:[1] The transportation industry, which has been largely dominated by ICEs, is one of the largest contributors to environmentally-damaging greenhouse gas emissions. Public awareness of the negative impact of these emissions has grown and government regulators are also demonstrating increased concern over regulations to curb these emissions. Transportation electrification, including that of fleet vehicles, reduces these emissions and will continue to increasingly and substantially reduce this contribution over time as emissions regulations and concerns are growing. This will inevitably spur growth in EVs, including fleets, as they offer an environmentally-conscious alternative.

Based on the growing evolution of these factors, the Company believes that it is now time to learn alongside customers who are early adopters, and internally prepare to meet fleet

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[1] Bloomberg New Energy Finance. (2019, May 15). Electric Vehicle Outlook 2019. Retrieved from https://www.bnef.com/core/insights/20667/view

customer needs to ensure that the additional EV load is a benefit and not a burden to all grid customers.

Q. What is the current and forecasted market for EV fleets in the U.S.?

A. In its evaluation of EV fleets, the Company examined the use of light, medium, and heavy-duty commercial EVs. According to the data surveyed by the Company, there are over 80 million commercial vehicles in these three categories currently being utilized in the U.S., and approximately 1.2 million in additional commercial vehicle sales annually.[2] Less than 0.5% of existing commercial vehicles are currently electric.[3] Thus, the EV fleet market is emerging, but still in its early stages as medium and heavy-duty EV options come available to buy. The number of EV fleet vehicles being utilized in the U.S. is forecasted to grow from approximately 240,000 today to 9.5 million by 2030, and 40 million by 2040.[4] The stages of EV commercialization vary widely by application, as seen in Figure 1 below. Of these segments, city buses and light-duty vans are rolling out fastest in their use, followed by school buses.

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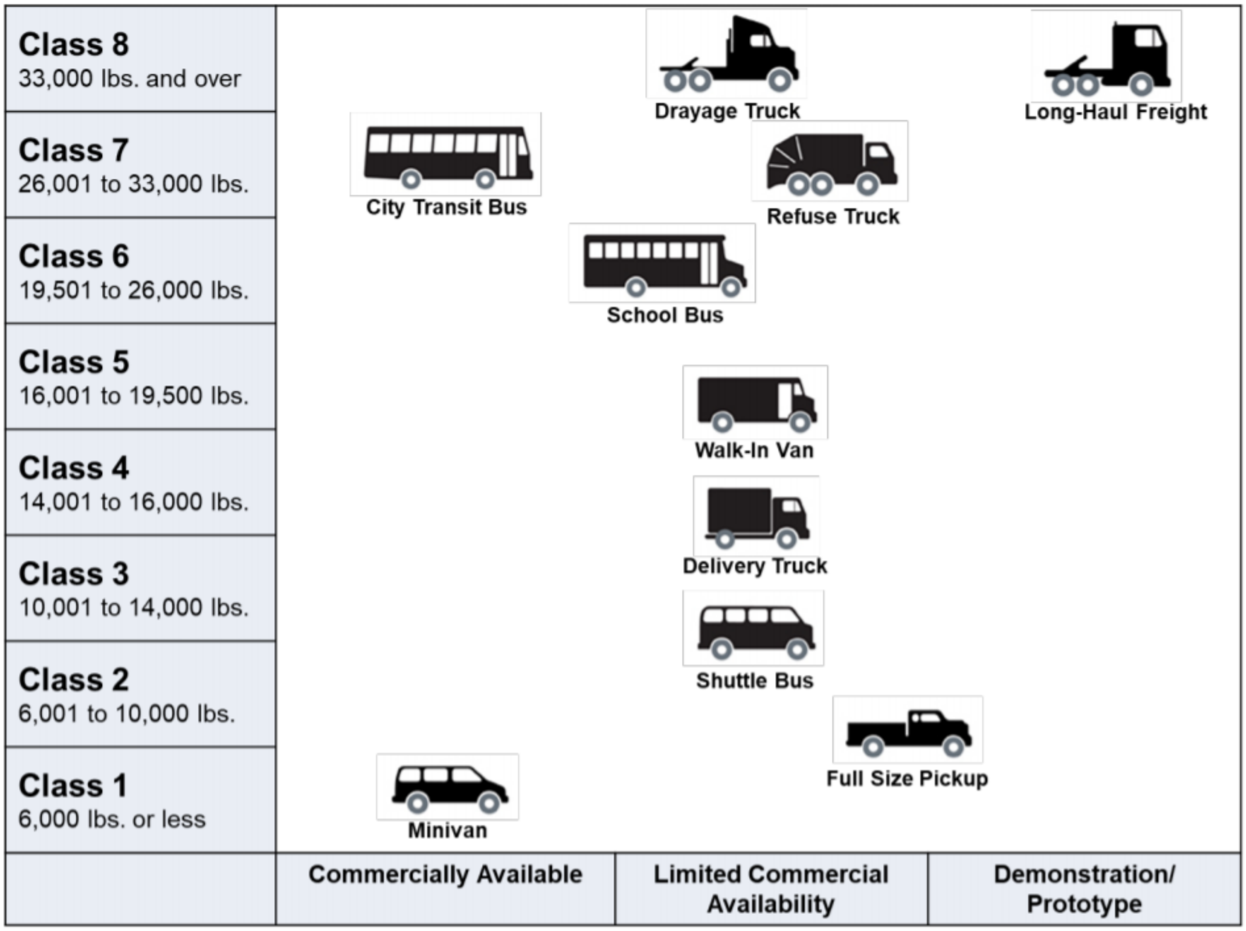
[2] Bloomberg New Energy Finance. (2019, May 15). Electric Vehicle Outlook 2019. Retrieved from https://www.bnef.com/core/insights/20667/view
[3] Id.
[4] Bloomberg New Energy Finance. (2019, May 15). Electric Vehicle Outlook 2019. Retrieved from https://www.bnef.com/core/insights/20667/view

Figure 1: Stages of EV Commercialization for Select Fleet Applications[5]



Q. Does the Company have any additional information regarding fleet demand trends?

A. Yes. A sign of fleet market momentum is information collected from emerging group buying consortiums such as the Climate Mayors and Corporate Electric Vehicle Alliance ("CEVA"). The Climate Mayors is a network of U.S. mayors working together to "demonstrate leadership on climate change through meaningful actions in their communities, and to express and build political will for effective federal and global policy action." See Climatemayors.org. According to the Climate Mayors website, in January

[5] Edison Electric Institute. (2019, October). Preparing To Plug In Your Fleet: 10 Things To Consider. Retrieved from https://www.eei.org/issuesandpolicy/electrictransportation/Documents/PreparingToPlugInYourFleet_FINAL_2019.pdf

2017, the City of Los Angeles released an EV Request for Information (EV RFI) with 30 other cities in order to determine municipal demand for EVs across the U.S. The results of the EV RFI demonstrated a municipal demand for nearly 115,000 medium and heavy-duty EVs based on 40 responses received across all vehicle segments. This level of demand equates to an estimated value of $10 billion to replace entire fleets in these categories.[6] Importantly, the results of this EV RFI clearly demonstrate the demand for electric medium and heavy-duty vehicles and provides insight into the size of the near-term market for manufacturers. Similarly, the CEVA, organized and led by the sustainability group CERES, is a collaborative group of companies focused on accelerating the transition to electric vehicles which "supports companies in making and achieving bold commitments to fleet electrifications." See Ceres.org. The development of these types of alliances, which are focused on the promotion of light, medium, and heavy-duty EVs, is similar to the early consortiums that organized to promote renewable energy buying, and suggests the light, medium, and heavy-duty EV market is poised for growth.

Q. What is the status of the EV fleet market in Michigan today?

A. In Michigan, electric school buses and city buses are the first commercial fleet vehicles demonstrating growth. For example, through the Volkswagen (VW) Settlement funds, managed by the Michigan Department of Environment, Great Lakes, and Energy ("EGLE"), 7 school districts will receive 1 to 3 electric school buses for a total of 17 electric school buses, to be purchased and deployed in the next year. In the next round of VW Settlement funding, EGLE plans to target medium and heavy-duty trucks, incentivizing that market as well. Further, the Detroit Department of Transportation plans to deploy six

[6] Climate Mayors. Electric Vehicle Request for Information (EV RFI). Retrieved from http://climatemayors.org/actions/initiatives/

electric buses in the city of Detroit by 2021, and the Company anticipates that cities in Consumers Energy's territory will add to their fleets as well. Finally, cities such as Kalamazoo and Grand Rapids also have climate and sustainability goals, which involve emissions reductions from the transportation sector; electric fleets could provide a key component of those goals.

Q. What are the benefits of EV fleets?

A. As discussed below, there are a number of benefits of transportation electrification, including transportation electrification of fleets, such as:

- downward pressure on electric rates;
- lower total cost of vehicle ownership; and
- environmental benefits.

Q. Which groups will be impacted by the benefits of EV fleets?

A. A number of Consumers Energy's customers will be impacted and benefit from EV fleets. For example, (i) families with school children will benefit from the availability and use of electric school bus fleets; (ii) public transportation patrons will benefit from the availability and use of electric city bus fleets; (iii)fleet owners will benefit from lower total cost of ownership, and a healthier experience for drivers; and (iv) society will benefit from lower emissions and improved air quality

Q. What is Consumers Energy's primary interest in pursuing an EV fleet Pilot program?

A. The Company is interested in conducting a pilot that provides grid management learning as it relates to fleets and in public infrastructure as a mechanism for serving the most people. Additionally, however, the Pilot is expected to offer unique educational opportunities such as the STEM-related learnings and public awareness and familiarity with electric vehicles. Thus, investment in PowerMIFleet goes beyond the key aspects of learning about managed charging and EV fleet customer needs for Consumers Energy; it helps position Michigan for future success on transportation technology and environmental fronts.

Q. How will Consumers Energy's customers benefit from the Company's proposed EV fleet Pilot?

A. From a regulatory perspective, increased EV adoption will put downward pressure on electric rates by spreading fixed costs over increased electric load, which will ultimately reduce electric rates for all customers due to improved grid utilization. To realize and maximize benefits to the grid and all system users, it is important to properly manage the incremental load resulting from EV adoption to ensure increased grid utilization and avoid increasing system peak loads.

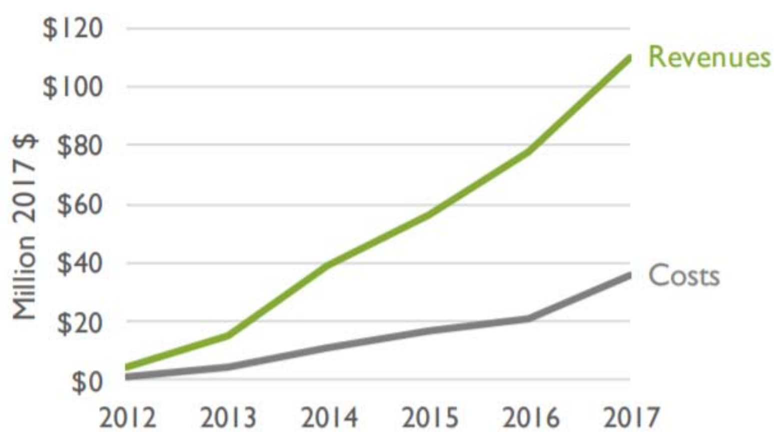
Q. Why is the Company's Pilot important?

A. The Company is uniquely positioned to provide the basis for the realization of the "lifetime value" of grid benefits for system users through a combination of reinvesting benefits towards EV infrastructure, rebates, pilots, and reducing rates across all customers, including non-EV drivers. The financial benefit that each incremental EV adds to the system is a resource that could benefit all Consumers Energy customers.

Q. Does the Company have any support for the anticipated benefit to customers?

A. Yes. Early support of the Company's Pilot can be found in a February 2019 analysis by Synapse Energy Economics, Inc. which found that "from 2012 through 2017, EVs in California have increased utility revenues more than they have increased utility costs, leading to downward pressure on electric rates for EV-owners and non-EV owners alike[7]." Figure 2 shows the Pacific Gas & Electric Company ("PG&E") revenues and costs over that time.

Figure 2: PG&E Revenues and Costs Associated with EVs[8]

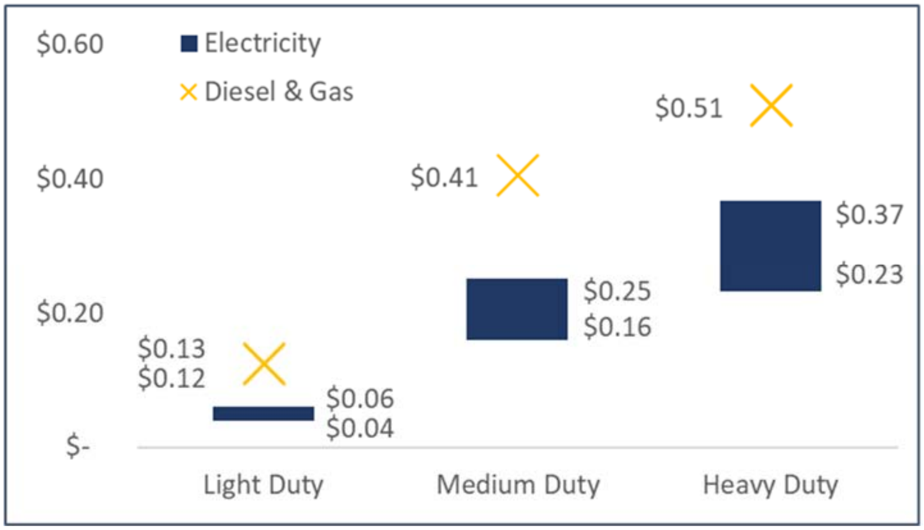


Q. Is there an anticipated benefit to EV fleet owners?

A. Yes. Fleet owners who purchase EVs will benefit from lower total costs of ownership, compared to gasoline vehicles, as well as support corporate sustainability goals. One of the largest contributors to lower total cost of ownership of electric vehicles is the reduced fuel cost. Figure 3 below shows the fuel cost per mile of an illustrative light, medium, and heavy-duty electric vehicle compared to diesel and gas vehicles, using Consumers Energy's electric rates. In all cases, electricity costs are less per mile driven compared to gasoline and diesel costs.

[7] Synapse Energy Economics, Inc. (2019, February). Electric Vehicles Are Driving Electric Rates Down. Retrieved from https://www.synapse-energy.com/sites/default/files/EVs-Driving-Rates-Down-8-122.pdf
[8] Synapse Energy Economics, Inc. (2019, February). Electric Vehicles Are Driving Electric Rates Down. Retrieved from https://www.synapse-energy.com/sites/default/files/EVs-Driving-Rates-Down-8-122.pdf

Figure 3: Fuel cost ($/mile) comparison by vehicle and electric rate



Q. Are any assumptions included in data demonstrated on Figure 3?

A. Yes. As discussed above, Figure 3 shows the gas and diesel cost per mile compared to the electric fuel cost per mile for a business customer. The analysis assumes the following with respect to the electric fuel cost per mile:

- Due to the demand charge structure of the delivery charge in the electric rates, the General Service Secondary Rate GS distribution charge of $.0492/MWh is used in all cases to be conservative;
- The range of values is due to (i) the time of day, (ii) the season, and (iii) whether the customer is on the General Service Secondary Time-of-Use Rate ("GSTU") or the General Service Primary Time-of-Use Rate ("GPTU");
- The analysis does not contemplate a business customer on a demand rate because most of the rate is based on the Maximum Demand which varies significantly from customer to customer; and
- Additional fuel cost assumptions for this analysis are as follows:

		Gas	Diesel	Electric
Fuel cost/ gallon		$2.70[9]	$3.01[10]	GSTU/GPTU
Miles/gallon or kWh	Light-duty	22.00[11]	23.90[12]	2.94[13]
	Medium-duty	6.64[14]	7.40[15]	0.71[16]
	Heavy-duty	5.29[17]	5.90[18]	0.49[19]

Q. What are the societal benefits of EV fleets?

A. Some of the societal benefits of electrifying fleets include greater access to and use of public vehicles, environmental benefits from the reduction in fossil-fuel emissions, and the elimination of diesel fumes. Many customer fleets will be used by the public, whether directly (i.e., public transportation, school buses) or indirectly (i.e., local government and municipal fleets, refuse vehicles). Additionally, the transportation sector (29%) has surpassed the electricity generation sector (28%) to become the largest contributor of greenhouse gas emissions,[20] and electrification will substantially reduce this contribution over time. Finally, all drivers sharing the roadways will benefit from quieter EVs, cleaner air, and the elimination of diesel fumes.

[9] AAA. Michigan Average Gas Prices. Retrieved from https://gasprices.aaa.com/?state=MI
[10] AAA. Michigan Average Gas Prices. Retrieved from https://gasprices.aaa.com/?state=MI
[11] United States Department of Transportation. Average Fuel Efficiency of U.S. Light Duty Vehicles. Retrieved from https://www.bts.gov/content/average-fuel-efficiency-us-light-duty-vehicles
[12] United States Department of Transportation. Average Fuel Efficiency of U.S. Light Duty Vehicles. Retrieved from https://www.bts.gov/content/average-fuel-efficiency-us-light-duty-vehicles
[13] Argonne National Laboratory. (2018, January). Impacts of Electrification of Light-Duty Vehicles in the United States, 2010 – 2017. Retrieved from https://publications.anl.gov/anlpubs/2018/01/141595.pdf
[14] Federal Highway Administration. (2016). Average Fuel Economy of Major Vehicle Categories. Retrieved from https://afdc.energy.gov/data/10310
[15] Federal Highway Administration. (2016). Average Fuel Economy of Major Vehicle Categories. Retrieved from https://afdc.energy.gov/data/10310
[16] National Renewable Energy Laboratory. (2016, December). Field Evaluation of Medium-Duty Plug-in Electric Delivery Trucks. Retrieved from https://afdc.energy.gov/files/u/publication/field_evaluation_md_elec_delivery_trucks.pdf
[17] Federal Highway Administration. (2016). Average Fuel Economy of Major Vehicle Categories. Retrieved from https://afdc.energy.gov/data/10310
[18] Federal Highway Administration. (2016). Average Fuel Economy of Major Vehicle Categories. Retrieved from https://afdc.energy.gov/data/10310
[19] Department of Mechanical Engineering, Carnegie Mellon University. (2018, April 16). Quantifying the Economic Case for Electric Semi-Trucks. Retrieved from https://arxiv.org/pdf/1804.05974.pdf
[20] United Stated Environmental Protection Agency. Greenhouse Gas Emissions. Retrieved from https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions

Q. What are the barriers to fleet electrification?

A. The barriers to fleet electrification are the same as the barriers for all EVs, with some additional unique characteristics. Two of the largest barriers for all EVs are consumer awareness and knowledge of EVs. Additionally, as with all EVs, there are barriers related to range anxiety due, in part, to geographic gaps in charging infrastructure.

Q. What are the unique barriers related to fleet electrification?

A. Cost is one of the unique barriers because fleet electrification has high upfront costs. Overall, EV retail prices are higher than ICE models (see Figure 4 below). In addition, EV owners need to install charging infrastructure. For fleets, these costs are magnified not only due to the number of vehicles and charging infrastructure required by fleets, but also because the larger electricity requirement means a higher likelihood of needing to upgrade on-site energy capacity.

Figure 4: Upfront cost comparison between EVs and ICE vehicles[21]

Vehicle	ICE	EV	
	Diesel & Gas	*Hybrid*	*Battery*
School Bus	$100k	-	$330-375k
Transit Bus	$380-420k	$630-650k	$750-1,000k
Delivery Van	$47k	-	$50-180k
Medium Truck	$77-100k	-	$400k
Freight Truck	$134k	$250k	$150-300k

Q. Please explain the additional costs involved in EV purchases and use.

A. As set forth in Consumers Energy witness Michael J. Delaney's Exhibit A-76 (MJD-4) in Case No. U-20134 (Consumers Energy's 2018 Electric Rate Case), Level 2 charger costs range from $500 to $8,000, with installation of those chargers costing an additional $600 to

[21] Atlas Public Policy. (2019, July). Electric Trucks and Buses Overview. Retrieved from https://atlaspolicy.com/rand/electric-trucks-and-buses-overview/

$8,000. Direct current fast chargers ("DCFC") range from $15,000 to $40,000, with installation of those chargers costing an additional $8,000 to $50,000. Hardware costs vary significantly for DCFCs based on the charging capacity. For example, a 175kW DCFC may have costs upward of $100,000 depending on the size of the charger and accompanying installation costs.

Q. Are there other unique barriers to fleet EV ownership?

A. Yes, another unique barrier to fleet EV ownership is model availability. Until recently, the number of commercially available EV fleet models for purchase was lacking. Now, however, transit buses and school buses are increasingly being placed in service, with more vehicles becoming available for purchase in 2020 and beyond. For example, original equipment manufacturers such as Rivian[22], Tesla[23], and Bollinger are taking deposits for the manufacture and sale of vehicles that they plan to release in the next couple of years. While production dates have been estimated for some of these vehicles starting in 2020, there is currently a lack of clarity regarding actual delivery dates.

Q. Do you have examples of the possible roll-out of any all-electric medium and heavy-duty vehicles?

A. Yes, all-electric medium and heavy-duty vehicles that have been announced include:

- Freightliner eM2 106: medium-duty delivery truck;
- Peterbilt Motors 220EV: medium-duty truck;
- Navistar eMV: medium-duty truck;
- Freightliner eCascadia: heavy-duty highway tractor;

[22] Kelley Blue Book. (2019, June 14). Rivian Pricing, Availability, Details. Retrieved from https://www.kbb.com/car-news/rivian/2100006867/
[23] Electrek. (2019, April 25). Tesla delays electric semi truck production to next year. Retrieved from https://electrek.co/2019/04/25/tesla-semi-delay-electric-truck-production-next-year/

- Mack Trucks LR BEV: heavy-duty refuse truck;
- Tesla Semi: heavy-duty truck; and
- Volvo VNR: heavy-duty regional-haul truck.

Q. What other barriers exist to fleet electrification?

A. Use complexity and the weighing of costs to benefits also represent barriers to fleet EV ownership and use. First, there is use complexity. In this complexity, there is significant variety in fleet parameters that make it difficult to have standardized electrification solutions. The variability in vehicle sizes, daily miles traveled, standard or non-standard routes, nightly vehicle location, and fleet ownership/operating model from fleet-to-fleet makes it difficult to educate fleet customers collectively on how the benefits of electrification apply to any individual situation. Second, is the focus on cost/benefit analysis. Fleet owners make purchase decisions based on total cost of ownership ("TCO") and look for a positive return on investment. Bloomberg New Energy Finance ("BNEF") analyzed total cost of ownership for battery electric and range-extender electric light and heavy-duty vehicles compared to their diesel and natural gas counterparts. BNEF determined that range-extender electric light-duty commercial vehicles in the U.S. have the lowest TCO for regional routes of all fuel types. BNEF forecasts that all light-duty trucks will be cheaper than diesel trucks by 2022[24].

Q. What appears to influence fleet customers?

A. As a group, fleet customers are more focused on functional attributes of vehicles that will serve their fleet needs, and are less swayed by personal preferences and emotional or social factors. Thus, if upfront costs decrease or are otherwise reduced and more models become

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[24] Bloomberg New Energy Finance. (2019, August 5). Commercial Vehicle Economics. Retrieved from https://www.bnef.com/core/insights/21089/view

more widely available, it becomes imperative for the Company to prepare for this change which could lead to potential rapid adoption of EV fleets.

Q. What is the Company's role in solving barriers to fleet electrification?

A. The Company's role is to make prudent investments now to learn alongside our early adopter customers while the fleet EV market is small, to help ensure that an eventual larger load of electric vehicles on the grid results in a benefit to all grid customers rather than a burden, through managed charging and partnership with our customers. This proposed Pilot is, thus, consistent with MPSC Staff ("Staff") testimony in Case No. U-18368, which asserted that, "[t]he Commission made it clear in its orders that it views utility vehicle electrification pilots as necessary to prudent planning by utilities."

Q. Are there any additional reasons for the timing of this EV fleet Pilot?

A. Yes. In addition to early grid management learning, it is important for the Company to pursue this pilot now, while there are still VW Settlement funds available to assist customers with some of the up-front costs discussed above. Because those funds are finite, this opportunity to match customers with those funds will not exist later to maximize investments in Michigan.

B. <u>Potential Impact of Fleet EVs on the Electric Grid</u>

Q. How might fleet EVs impact the electric grid in Company territory?

A. The primary goal of Consumers Energy's overall EV strategy is to ensure that EVs benefit the grid, and benefit Consumers Energy's customers. While passenger vehicles are predominantly light-duty, fleet vehicles will include medium and heavy-duty vehicles, which will impact the grid much differently. Fleet vehicles will often be medium and heavy-duty vehicles with larger batteries and are more likely to cluster in one area. This creates a very high likelihood of higher demands on the local electric grid infrastructure than what is typically seen in the residential market. Moreover, there are likely to be some fleet applications that have difficulty managing time of use charging; thus, learning from these experiences now helps the Company understand these impacts and prepare for future planning and management standards.

Q. Please explain the demands of medium and heavy-duty vehicles on the grid.

A. Medium and heavy-duty vehicles will put much higher demands on the grid than light-duty vehicles (see Figure 5 below). For example, the 2019 Chevrolet Bolt EV, a sedan, is rated at 3.6 miles per kilowatt hour (kWh)[25] compared to the Freightliner eCascadia, a class-8 heavy-duty highway semi-tractor-trailer which is expected to start production in 2021, and is expected to achieve less than half a mile per kWh. The class-8 semi will, thus, require over seven times more electricity to travel the same distance. Assuming average annual vehicle miles traveled by vehicle type[26], a fleet of 20 sedans requires the same amount of electricity as three school buses or a single transit bus. This is similar to the electricity required to power over eight homes for a year

[25] U.S. Department of Energy. Find and Compare Cars. Retrieved from https://www.fueleconomy.gov/feg/noframes/40520.shtml

[26] Federal Highway Administration. (2016). Average Annual Vehicle Miles Traveled by Major Vehicle Categories. Retrieved by https://afdc.energy.gov/data/10309

Figure 5: EV charging profiles by vehicle class and charging speed

Additionally, as shown in Figure 5, the size of the EV battery, and the speed at which the battery is charged, will determine the load profile. The Company is working with customers to ensure that they develop the most cost-effective charging solutions for their business, which is to the benefit of all customers.

Q. Why is it important for Consumers Energy to proactively manage grid impacts from EVs?

A. As the MPSC stated in its March 29, 2018 Order Following the Second Collaborative Technical Conference in Case No. U-18368, "[b]ecause of the inherent uncertainties in PEV adoption rates, it is essential that utilities be proactive in understanding and mitigating potential impacts to the grid (and related infrastructure costs) under different PEV adoption scenarios." Additionally, the Commission stated, "[i]f well-planned, executed with the right price signals, and coordinated with third parties on the placement of chargers, there is the potential for all customers to benefit from increased electrification of the transportation sector."[27] The Company's PowerMIFleet Program is part of this necessary proactive approach.

C. Cost/Benefit Analysis of Fleet EVs

Q. What approach did the Company take to analyze the benefits and costs of the Program?

A. To calculate the benefits of fleet electrification, the Company analyzed the value of the incremental load of various EV types including light, medium, and heavy-duty EVs. To calculate the costs, the Company's overall approach is similar to the cost/benefit analysis utilized in the Company's 2018 Electric Rate Case, Case No. U-20134, for the

[27] MPSC. (2018, March 29). Order Following the Second Collaborative Technical Conference. Retrieved from https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000002286r

PowerMIDrive pilot program. Unlike the PowerMIDrive Program, which addresses mostly passenger vehicles, the variety of fleet types, use cases, and configurations (e.g., number of vehicles and where they are located) add complexity to the cost/benefit analysis. This lends to the need for the PowerMIFleet Program to be a pilot – because there is larger variability in learning due to the inherent uncertainty that comes from the wider range of vehicle types and sizes impacting the grid.

Q. What are the anticipated benefits of fleet EVs to the grid?

A. Similar to the cost/benefit analysis used in Case No. U-20134 to support the PowerMIDrive pilot program, Exhibit A-90 (SRN-1) is an analysis to demonstrate the benefits of incremental electric load for electric vehicle charging for fleet vehicles, including those in the medium to heavy-duty size. It is important to note in this analysis, compared to the analysis for passenger vehicles, fleet vehicle benefits vary widely depending on assumptions for:

- Vehicle efficiency;
- Vehicle mileage; and
- Customer class (i.e., Primary or Secondary).

Q. Please explain Exhibit A-90 (SRN-1).

A. Exhibit A-90 (SRN-1) illustrates two scenarios: one assumes Secondary Rate Class customers, and one assumes Primary Rate Class customers. For each scenario, Exhibit A-90 (SRN-1) provides capacity calculations, additional capacity and distribution revenue from off-peak charging, the lifetime value analysis, and the assumptions used to calculate estimated annual EV energy use.

Exhibit A-90 (SRN-1) demonstrates that adding a medium or heavy-duty electric vehicle to the grid provides a much larger "lifetime value" compared to the light-duty vehicle analysis shown in Case No. U-20134 in support of the Company's PowerMIDrive pilot. In Case No. U-20134, Company witness Michael J. Delaney presented an analysis showing an estimated benefit of $1,900 to $2,300 of "lifetime value" for each light-duty electric vehicle added to the grid. As Figure 6 below further demonstrates, the lifetime value for medium and heavy-duty vehicles is estimated to range from $5,000 to $18,000 for customers on a Primary rate and $11,500 to $42,000 for customers on a Secondary rate.

Figure 6: Fleet electric vehicle cost/benefit analysis for Consumers Energy territory summary

Vehicle type	Annual Mileage	Avg Mi/kWh	Secondary Customer Lifetime Value	Primary Customer Lifetime Value
Medium-duty delivery	12,958	0.7	$11,510	$5,009
School bus	12,000	0.5	$13,528	$5,888
Transit bus	34,012	0.5	$42,085	$18,315

This lifetime value per EV can lead to downward pressure on rates by increasing revenue and increasing grid utilization in the early morning when usage is typically low. Consumers Energy will seek customers who are able to primarily charge vehicles off-peak, which will result in the lowest overall cost for the Company, the customer, and the entire customer base.

Q. What are the anticipated costs of adding fleet EVs to the system?

A. Due to fleet vehicles' large batteries and likelihood of colocation, the Company must assume infrastructure upgrades will be required in some cases to support the additional electric load required for those vehicles. Again, this varies depending on the types and number of chargers and vehicles at any given location on the system.

Additionally, overall capacity needed by an EV fleet will be important. On the low end, a typical Level 2 charger installed at a residence has capacity of approximately 7kW. A higher capacity Level 2 charger for commercial applications such as school buses can go up to approximately 19kW. As stated previously, a single charger for one of these charging applications could have a minimal installation cost or go up to nearly $10,000. Costs to serve and infrastructure upgrade costs increase significantly with the increase in the charging capacity needed for a group of Level 2 chargers or a couple of DCFCs that could have capacity of more than 250kW.

Q. Please explain the costs of charging stations based on capacity.

A. For new EV charging capacity ranging from 50 kW up to 425 kW, costs to serve and infrastructure upgrades could range from $30,000 to $45,000, with more challenging sites having even higher costs (e.g., metropolitan or rural areas). The costs associated with the installation of charging facilities with a capacity of 425kW or larger may exceed $100,000 when including necessary upgrades.

Another cost consideration when making infrastructure upgrades is future-proofing. In practice, it may make sense to upgrade infrastructure at certain locations to approximately 400kW (or the maximum capacity before a more significant upgrade is required) in order to allow for advances in technology and additional charging capacity.

The Company plans to allocate program resources based on a number of factors including project make-ready cost for infrastructure upgrades. The number of EVs a company is adding to the grid can be balanced against the cost of infrastructure upgrades.

Q. How will the Company balance Program benefits and costs?

A. The Company's approach is to learn while the market is evolving to ensure maximum benefits to all customers as the EV market grows. The Company will maximize benefits by:

1. Prioritizing customers who can primarily charge during off-peak hours;
2. Pursuing fleet applications that benefit the public such as school buses, transit buses, and city vehicles; and
3. Exploring how EV fleets could operate as a storage resource for grid services such as demand response and emergency backup for buildings given that the batteries in EVs have the potential to become integrated as battery storage assets.

The Company will keep costs controlled to the amount approved for this Pilot program and utilize cost savings to further partnerships with public applications. This approach will allow Consumers Energy to ensure that EVs are a benefit and not a burden to the electric grid while balancing customer benefits and costs.

II. Pilot Program Proposal: PowerMIFleet

A. Objectives

Q. What are the objectives of the proposed pilot program, PowerMIFleet?

A. Similar to the Company's PowerMIDrive pilot, the main objective of the Program is to ensure Consumers Energy is prepared to facilitate the full benefit of EV adoption for all customers by learning to manage grid impacts while the EV market is small, thereby being well-positioned to capture benefits for customers while avoiding expensive, reactive adjustments once the market has matured. Other objectives include delivering a seamless customer experience and facilitating customer EV adoption.

Q. How is PowerMIFleet designed?

A. PowerMIFleet is designed to enable Michigan EV fleet customers to own and operate electric vehicles by facilitating on-site and in-route charging, both Level 2 and DCFC, across Consumers Energy's electric territory. While the PowerMIDrive pilot is designed to seed the EV market in Consumers Energy's electric territory with an initial investment in public infrastructure, PowerMIFleet will expand the Company's learnings into how medium and heavy-duty electric vehicle charging will impact the grid. The Company plans to approach this with an emphasis on learning by working closely with fleet owners, fueling stations, the Company's internal fleet team, and other stakeholders to help fleet owners understand the cost savings associated with electrification, effectively manage charging to benefit all, and explore new value streams for vehicle batteries to determine future steps to take.

B. Proposed Program Details

1. Program Overall

Q. What are the components of the proposed Program?

A. As will be discussed in more detail below, there are five components of the Program:

1. Fleet Charging Infrastructure;
2. Workplace Demand Response;
3. Bi-Directional Power Flow Demonstration;
4. Education & Outreach; and
5. Technical Development.

Q. How long are you proposing the Program run?

A. Consumers Energy proposes to run the Program for three years after program launch, which is anticipated to be approximately 2021 to 2024.

Q. What role will the Company play in deploying infrastructure?

A. The Program is proposed as rebate offerings under a "make-ready" model, rather than Company ownership. This means that rebates for Level 2 and DCFC charging can be applied to costs associated with supply infrastructure (i.e. panel and wiring) and the charger equipment itself. Under the make-ready model, the Company would pay for the total cost of installing the service connection, similar to PowerMIDrive. Make-ready costs may also supplement the workplace demand response and bi-directional power flow components behind the meter for sites engaging in such pilot programs. The Company will be proactive in identifying and encouraging sites for this Program that require minimal service connection investment.

Q. What are the rebate requirements?

A. Rebate and make-ready terms will dictate maintenance, equipment choice, and Company data/demand response access. The main requirements for participants are as follows:

- Be an existing Consumers Energy electric customer;
- Choose from a Company-approved list of EV chargers which meet the minimum standards required to carry out data collection and demand response;
- Share charging data with the Company (e.g., timing, frequency, and utilization); and
- Enable the capability for the Company to conduct demand response testing and/or programs during the three-year pilot Program; individual event testing would be an opt-out option for users.

2. Fleet Charging Infrastructure Component

Q. How is fleet defined and what vehicles and charging infrastructure are being targeted by the Program?

A. Fleet includes any Consumers Energy electric customer's company fleet vehicles as well as electric customer companies that may or may not a company-owned fleet, but have a number of employees with EVs (employee-owned vehicles). Thus, fleet can be light, medium, and heavy-duty vehicles.[28] The primary use of any electric vehicle supply equipment ("EVSE") supported by the Program will be to charge customers' company fleet and employee-owned vehicles. The EVSE is not required to be open to the public but may be publicly accessible if it is placed in an employee parking area that is also open to the public.

Q. Are you treating fleet vehicles of a company differently from employee vehicles located at that same workplace?

A. No. It is important to incorporate both fleet and employee vehicles in the Program. Access to workplace charging has been shown to be particularly effective in catalyzing the EV market; an employee is six times more likely to own an EV if they have access to charging at work.[29] Increasing driver familiarity with managed charging at work could also result in more informed charging at home. Companies, like Consumers Energy, who understand the importance of transportation electrification in reducing greenhouse gas emissions and realizing savings are both electrifying their internal company fleets as well as facilitating

[28] Based on the needs of an electric customer – whether it owns its own fleet or has a number of employee-owned vehicles – the electric customer may be able to take advantage of the PowerMIDrive program (which would require the charging stations to be publicly available) or the PowerMIFleet program (which provides the option of public or non-public charging stations).

[29] U.S. Department of Energy. (2015, December). Workplace Charging Challenge Mid-Program Review: Employees Plug In. Retrieved from https://afdc.energy.gov/files/u/publication/wpcc_mid-program_review.pdf

employee EV adoption by providing workplace charging. The Company wants to support these customers through the PowerMIFleet Program and learn more about what fleet and employee workplace charging load profiles entail for EV programs and future distribution planning.

Q. What are the details of the fleet charging infrastructure component?

A. The fleet charging infrastructure component proposes to enable customers interested in electrifying their fleets to install Level 2 and DCFC EVSE to meet their electric vehicle charging needs in a way that is beneficial to all customers. To accomplish this, the Company will use the make-ready model and provide rebates for customer EVSE. This approach is similar to PowerMIDrive.

Q. What are the details of the make-ready model?

A. The make-ready model would allow the Company to invest in utility assets including the installed cost of the service, transformer, meters, and associated equipment upstream of the EV supply infrastructure. In Case No. U-20134, Staff witness Robert G. Ozar, P.E., recommended the addition of a make-ready component to the PowerMIDrive pilot. Mr. Ozar stated, "[t]he additional funding for 'make ready' interconnection costs should make the PowerMIDrive pilot a stronger pilot and more likely of achieving intended goals." In addition, Mr. Ozar stated, "Consumers would have the unilateral right to suspend CIAC at any particular Level-2 or DCFC site included in the pilot, and thus fully fund the cost of interconnection." The Company is proposing to apply the same make-ready model with the suspension of contributions in aid of construction to the PowerMIFleet Program. Furthermore, make-ready funds will also support workplace demand response and bi-directional power flow program components.

Q. What are the details of the rebates for Level 2 chargers?

A. Similar to PowerMIDrive, the Company will offer a rebate for the installation of Level 2 charging stations. A rebate of up to $5,000 per port will be limited to 500 charging ports, for a total cost of $2.5 million over the three years of the Program. Customers will be eligible for up to $100,000 of Level 2 rebates per site or up to 20 charge ports per location. This design will allow for 25 or more total locations be to be included in the program, and a variety of customers to participate.

In order to be eligible for the rebate, and in addition to the overall conditions outlined above, a site host must adhere to a maintenance program, which may be carried out by the site host directly or the third-party vendor who is managing the site.

Q. What are the details of the rebates for DCFC?

A. For the installation of a DCFC, the Company proposes to provide a rebate not exceeding $70,000 for public-use chargers and $35,000 for non-public chargers per 125 kW of DCFC charging capacity. Public-use chargers are defined as sites that allow and publicize access for public charging or sites that are charging public-facing vehicles such as school buses, transit buses, and government vehicles. Rebates will be limited to a total cost of $0.5 million over the three years of the Program. Customers will be eligible for up to $140,000 of DCFC rebates per site.

In order to be eligible for the rebate, and in addition to the overall conditions outlined above, a site host must:

- Install at least 125 kW of charging capacity. Dual ports on chargers will be required;
- Site hosts will be required to default into participation in demand response testing and/or programs during the Program; and

- Site hosts will be required to adhere to a maintenance plan, which may be carried out by the site host directly or the third-party vendor who is managing the site.

3. Workplace Demand Response Component

Q. What are the details for the workplace demand response component?

A. The Company is proposing a workplace demand response offering to explore the value of using groups of EVs as demand response assets. An asset is a "demand response asset" when its use of electricity can be controlled. This will allow the Company to call a demand response event to allow the Company to stop or slow charging during a given event time when the demand on the grid is too great and there is a need to reduce demand. This functionality would allow the Company to actively manage charging, as opposed to more passive approaches such as time-of-use rates and, thus, test the additional grid value of EVs. Commercial customers who receive EVSE rebates in PowerMIFleet would automatically be considered demand response program participants. Additionally, customers may be enrolled in the Program without receiving a rebate if they meet program criteria with existing equipment. Participants may receive compensation for participating in individual demand response events, similar to the Company's Commercial & Industrial Demand Response Program today. All participants would be able to opt out of any event.

Q. What do you expect to learn from the workplace demand response component?

A. The Company is looking to properly prepare for the EVs that are anticipated in the market, and that involves understanding the potential of these assets in demand response, how customers respond to curtailment, and to learn alongside customers who are purchasing the vehicles for personal or fleet use. This also supports the Company's long-term Integrated Resource Plan goals as an option to potentially expand the existing demand response portfolio, should the Program prove successful.

The Company is requesting the Commission approve funding for the Pilot in order to learn about potential for workplace EVs to be a demand response resource, and to test assumptions on cost of capacity, program participation, number of customer sites, number of events, and types of participating vehicles. The ability to collect actual data on these Program variables will allow the Company to determine the potential of a full program in the future.

4. Bi-Directional Power Flow Demonstration Component

Q. What are the details for the bi-directional power flow demonstration component?

A. The Company proposes a bi-directional power flow demonstration to explore new uses for vehicle batteries. This functionality would allow the Company to test vehicle-to-building ("V2B"), demand response, emergency backup power, and vehicle-to-grid ("V2G") in new ways.

Q. What is bi-directional power flow?

A. Electricity use is traditionally directional (1-way) wherein consumers draw electricity from the grid for use. Bi-directional power flow is the concept of the 2-way flow of electricity – the electricity can flow from the grid to a building, vehicle, etc., but can also flow from the battery of a vehicle, back to a building, back to the grid, etc. In this way, those vehicles offer extra storage, emergency backup (feeding battery-stored electricity back to a building), and grid-load balancing (many vehicles storing energy at low load demand hours and at less expensive prices to feed back to homes or offices during peak hours).

Q. Why is this important?

A. This bi-directional power flow demonstration is a critical component of the Company's fleet Program as it pertains directly to learning more about how medium and heavy-duty

EVs can be beneficial to the grid and provide additional benefits to vehicle owners. V2B is an example of an additional vehicle owner benefit that could reduce total cost of ownership of fleet EVs in the near-term.

The bi-directional power flow demonstration component will leverage charger rebates, make-ready infrastructure investment, and technical support from other components of the Program to operate. However, not all applicants will be required to participate in this component of PowerMIFleet. Instead, Consumers Energy will actively seek applicants interested in partnering on this learning opportunity.

Q. Which customers do you anticipate working with on this bi-directional power flow component?

A. The Company is open to working with any customer that owns or operates an electric fleet vehicle, although medium and heavy-duty EVs may offer the greatest opportunity due to their higher battery capacity. Furthermore, based on the current market dynamics, city buses and school buses are strong candidates for this type of program because they are commercially available to purchase, have defined routes and set charging locations, and have predictable downtime. Given the need to install EVSE and procure EVs, we anticipate that learnings will occur in the later portion of the Program.

5. Education & Outreach Component

Q. What are the details for the education and outreach component?

A. The education and outreach component is critical to ensuring that Consumers Energy is guiding the learning through collaboration and partnerships with customers. The Company will conduct an education and outreach program to recruit site hosts for employee fleet and company fleet Level 2 chargers and DCFCs, recruit customers for the electrification concierge and bi-directional power flow demonstration components, educate business customers on rates and smart charging, and increase education and awareness of EV opportunities overall. Education and outreach activities include, but are not limited to:

- Providing support to fleet customers interested in electrifying their fleet through a fleet electrification concierge offering (more details below);
- Creating awareness and increasing knowledge of EVs and the Program through customer outreach opportunities such as advertising and presentations at conferences and events;
- Expanding the capabilities of the Company's website to provide business customers fleet-focused information;
- Engaging municipalities across the state to work with local organizations that focus on business and economic development who have an interest in learning more about EV options; and
- Partnering with Michigan business and trade associations that have strong ties to local customer bases to conduct information sharing activities.

Q. What are the details for the fleet electrification concierge service?

A. The Company proposes introducing a fleet electrification concierge service to help customers develop a fleet electrification strategy. This service would require a close partnership with individual customers and may include:

- Analyzing fleet operations to determine electrification plan;
- Identifying electrification use cases that are economic;
- Analyzing vehicle usage needs to determine charging needs;
- Incorporating employee workplace charging considerations into EVSE needs;
- Recommending EVSE locations and facilitate installation;
- Analyzing electric rate options and determining optimal charging profile and rate; and/or
- Connecting customers to electric vehicle and EVSE providers.

The activities above will be completed by a combination of internal Company resources and third parties.

Q. Why is the Company including the education and outreach component as a part of the Program?

A. Due to the nascent nature of the medium and heavy-duty vehicle markets, many business customers are not aware of the benefits of fleet electrification and often are not prepared to fully compare EVs with traditional fleet vehicles. Some use cases are currently estimated to be economic while others are not expected to be for some time. Additionally, the cost/benefit analysis is complicated by use complexity and electric rate options. Consumers Energy is well positioned to help customers understand whether fleet electrification is likely beneficial to them now or what would need to be true to be economic in the future. Also, partnering with companies early in the fleet electrification process could help customers save money by making decisions about charging infrastructure based on grid impacts and total cost. The Company has capabilities to help determine where to construct EVSE at a specific customer location to be the most economic for that customer.

6. <u>Technical Development Component</u>

Q. What are the details for the education and outreach component?

A. Technical development is composed of two areas: Information technology ("IT") and administration. An IT/data system will be critical to ensure that the integration of EVs provides a benefit, rather than a burden, to the grid. This system will focus on the collection of data from smart meters, the collection of data from chargers, the collection of data from the vehicle itself, and/or the collection of data from a third-party device that collects charging data. Technology is constantly changing and there is not yet a clear choice for

EV charging data collection, or from more advanced applications such as demand response or bi-directional power flow. Flexibility and testing are, therefore, necessary to ensure that the Company is prepared to integrate with the leading technologies at any given time. The system is expected to allow for the communication and analysis of demand response events. The system created is also intended to be developed in a manner that allows for scalability for future growth in the EV market.

Administration is needed to manage recruitment, EVSE site selection, outreach and education, rebates, and relationship management between the Company and its customers, vendors, and other partners. The Company is proposing two full-time employees ("FTE") to implement and manage the Program.

Q. How does the Company envision the components coming together in a customer offering?

A. Interested fleet customers could participate in one or all components of the proposed Program. Some customers may want the initial concierge service to consider their options, while other customers may be ready to install chargers and apply for rebates. A fully-functional program could provide a comprehensive solution with guidance and planning from the concierge, charger rebates, make-ready infrastructure investment, and enrollment in the workplace demand response and/or bi-directional power flow offerings.

7. Evaluation of Program

Q. How will success of the Program be evaluated?

A. As stated above, the Program objective is to ensure Consumers Energy is prepared to facilitate the full benefit of EV adoption for all customers by learning to manage grid impacts while the EV market is small, thereby being well-positioned to capture benefits for customers while avoiding expensive, reactive adjustments as the market grows. This includes executing the program in a way that provides a seamless customer experience. In that light, the Program is being designed within a manner designed to resolve five issues, with associated evaluation criteria.

Issues to Resolve	Evaluation criteria
1. Education and awareness	• Participation
2. Charging data and managed charging	• Charging off-peak • Participation in demand response events
3. Customer cost/benefit analysis (including use complexity)	• Cost savings for fleet customer
4. High upfront costs of EVs and EVSE	• Participation • Cost savings for fleet customer
5. Realizing battery value streams	• Bi-directional power flow value use cases such as resiliency, demand response, etc.

To resolve these issues, recruitment and outcomes will be documented for customers, and surveys and interviews will be used to capture insights on items such as customer satisfaction, charger installation experiences or rationales for not pursuing EVs, preferred vendors, and customer awareness of EVs. Costs will be closely tracked to calibrate the estimates and learn for future programs. The Company will capture vital data on charging behavior, site utilization rates, and managed charging capabilities.

Q. How will the Program insights be captured and evaluated during the three years?

A. Rather than wait until the conclusion of the three-year Pilot period, similar to PowerMIDrive, Consumers Energy will dynamically assess and adjust the Program components based off the insights gained, evaluated with stakeholder meetings and then captured in annual Program reviews delivered to the MPSC. Program adjustments could include changes to the rebate levels, number of rebates, or technical specifications, depending on Program response and market/technological progress. The Company can leverage these lessons to design future programs and to share with other Michigan entities to improve outcomes across the state.

8. Projected Expense

Q. What are the estimated costs associated with each component of the Program identified above?

A. The chart below shows the estimated costs for each component of the Program. Estimated costs are $12.2 million for the three-year Program.

Component	Program Cost
Fleet Charging Infrastructure Capital O&M (Regulatory Asset)	 $4.5 million $3.0 million
Education & Outreach O&M (Regulatory Asset)	 $1.3 million
Technical Development O&M (Regulatory Asset)	 $3.4 million
Total **Capital** **O&M (Regulatory Asset)**	**$12.2 million** **$4.5 million** **$7.7 million**

Over the life of the Program, costs are expected to be:

- <u>Fleet charging infrastructure capital (make-ready)</u>: a three-year cost of $4.5 million;
- <u>Fleet charging infrastructure Operating and Maintenance (“O&M”) (Level 2 rebates)</u>: up to $5,000 per port (cost of the rebate), for a three-year cost of $2.5 million;
- <u>Fleet charging infrastructure O&M (DCFC rebates)</u>: up to $70,000 per public-use charger and $35,000 per non-public charger (cost of the rebate), for a three-year cost of $0.5 million;
- <u>Education and outreach</u>: a three-year cost of $1.3 million for resources to recruit customers and site hosts for the Program, as well as educate all customers on the benefits of EVs and managed charging;
- <u>Technical development</u>: a three-year cost of $3.4 million for the critical system underpinning charging data collection and analysis, demand response, and bi-directional power flow as well as allowance for two FTEs; and

- The fleet electrification concierge, workplace demand response, and bi-directional power flow components will leverage rebates and make-ready investment from the fleet charging infrastructure component as well as Program support from the education and outreach and technical development components to operate, so there are not incremental costs for these components.

Because the market is evolving, the annual costs are expected to vary depending on customer uptake of rebates and/or vehicle availability. Any differences between estimated costs for each program element above and reality will be discussed with the MPSC.

Q. Please provide your rationale for the Program costs.

A. The Company consulted a number of sources to determine Program costs, including reviewing industry research and studies, interviewing charging and network providers and other utilities, utilizing internal subject matter experts, benchmarking against other existing and proposed programs, and utilizing learnings from PowerMIDrive. For example, (i) costs for the Level 2 and DCFC infrastructure components, make-ready and charger hardware costs, are based on internal estimates, data points gathered from commercial charger providers, and industry reports; (ii) costs for the education and outreach component of the Program are based on internal estimates from marketing and coordination staff and benchmarked across comparable programs that have been approved or proposed to date; (iii) costs for technical development were estimated in a similar manner.

Directly comparable costs are difficult to find publicly, so approved and proposed programs were only used as a qualitative benchmark. Due to the company-specific nature of technical development, details of this component were thoroughly vetted and debated with internal human resources and IT departments. Additionally, for technical development costs, the Company is already benefitting from the short time PowerMIDrive has been operating.

Q. What has the Company learned from the PowerMIDrive Program?

A. The PowerMIDrive Program has provided actual cost information for elements such as make-ready infrastructure, charging equipment, and the cost to build out systems to collect charging data.

Q. Why is IT critical?

A. As stated in Case No. U-20134 in the direct testimony of Company witness Delaney, the IT costs will be critical to continue building out a foundational data and support capability to ensure secure communication links between charger equipment providers, charging network providers, EVs, smart meters, and current grid systems. IT costs include the purchase and development of new systems utilizing both internal capabilities as well as vendors. These systems will allow for the retrieval and processing of the data in order to ensure optimal grid performance and accurately deliver on the six measures of success discussed previously.

Regarding administration of the Program, it is expected that two FTEs will be required to run the Program through its completion.

The Company's initial fleet Program is designed to be foundational and scalable. Program costs may vary due to customer participation and timing. Consumers Energy is confident that this Program will build on the learnings from PowerMIDrive and help prepare the Company to best serve customers by testing approaches and learning while overall EV adoption is still low.

III. Request to Treat O&M Costs as a Regulatory Asset

Q. How will Program O&M costs be treated?

A. The Company requests to treat Program O&M costs as a regulatory asset. The proposed Program, if approved, would result in a deferred asset until the EV Program rebate and related O&M costs are confirmed. If this proposal is approved by the Commission, the Company requests approval to recognize a regulatory asset to record these deferred amounts. Please reference the direct testimony of Company witness Daniel L. Harry for further details on the proposed accounting treatment.

Q. Why is Consumers Energy proposing the regulatory asset approach for recovering Program costs?

A. The regulatory asset approach allows the Company to invest in EV charging infrastructure now to benefit Consumers Energy customers and recover those costs at a later date. A regulatory asset approach allows for prudency review prior to collection through rates. This is well-suited for a pilot where Program participation may vary significantly from initial expectations. Further, this approach spreads the recovery of Program costs and the cost of capital over the life of the EV charger assets which smooths out the impact on customers and aligns well with the expected lifetime benefits of the EV Program.

The regulatory asset approach allows the Company to invest in infrastructure now to manifest the customer benefits of EV adoption, gain learnings from the Pilot, and assess manageable load in Michigan without owning and operating charging infrastructure. This provides an incentive for Michigan businesses to begin electrifying vehicle fleets by accelerating charger availability and promoting awareness while keeping rates lower and expediting the benefits of EV adoption. Consumers Energy has a responsibility to act in the best interest of the Company's customers and the regulatory assets approach meets this need.

IV. Strategic Fit and Stakeholder Collaboration

Q. How does the proposed Program fit into the Company's overall strategy?

A. First, this Program supports the Company's two fundamental objectives for its EV program: (i) to help ensure that EVs are a benefit to grid customers, not a burden, and (ii) to provide a seamless customer experience. As the Company stated in Case No. U-20134, proactively working with customers and the new EV load and technology while the market is nascent will allow the Company to learn and prepare for an increased number of EVs on the grid. This is uniquely important for fleet vehicles, given their larger batteries and consolidated charging locations.

Second, this Program is in line with the Company's bottom line of serving people, planet, and prosperity, as explained in Company witness Michael A. Torrey's direct testimony. EVs decrease operating costs for drivers and grid customers and reduce air pollution and greenhouse gas emissions[30]. This Program is an excellent addition to the Company's Clean Energy Plan. As school and city buses electrify, it will increase public access to electric vehicles and their benefits. Finally, the Company is doing its part to maintain Michigan's prosperity by supporting Michigan's automotive legacy with this new evolution into electric mobility.

The Company plans to increase the number of internal fleet EVs and EVSE separate from the PowerMIFleet Program. The learnings from operations and charging behavior will also be incorporated into Program design and implementation.

[30] M.J. Bradley & Associates. (2017, August). Electric Vehicle Cost-Benefit Analysis. Retrieved from https://mjbradley.com/sites/default/files/MI_PEV_CB_Analysis_FINAL_03aug17.pdf

Q. How will the Company leverage its experience with EVs to support this new proposal?

A. The current EV program, PowerMIDrive, was built from the Company's experience with EV rates and offerings starting in 2012 as well as an extensive stakeholder engagement process. Learnings from these past EV efforts have informed this Program.

At this time, PowerMIDrive has been in operation for 6 months. There are several early learnings from PowerMIDrive that the Company can leverage in this Program, such as:

- <u>Customer demand</u>: Many companies are on the tipping point but not quite ready to make the jump without support/incentives. National companies are electrifying in states with attractive policies/programs;
- <u>Costs</u>: Level 2 charger and installation costs are coming in as estimated. Make-ready for DCFCs has been lower than expected, but that could change with fleet charging requirements; and
- <u>Data collection</u>: It is helpful to get in early and assist customers with hardware/software selections.

Q. How does PowerMIFleet compare to other utility programs?

A. PowerMIFleet is comparable to other utility EV program proposals. A handful of fleet-focused EV programs have been approved in the U.S., with many more waiting on approval. Below is a summary of select utility programs that have similar components to PowerMIFleet.

- <u>Fleet Charging Infrastructure</u>: Xcel Energy's Fleet EV Service Pilot employs a make-ready model for EV charging infrastructure that includes both the EV service connection and EV supply infrastructure for up to 700 fleet charging ports. Similarly, PowerMIFleet proposes the make-ready model for the EV service connection and a rebate to partially cover the cost of the EV supply infrastructure. Xcel's program differs from PowerMIFleet in that the utility gives customers the option to own the charging equipment or have Xcel own the charging equipment. Other utilities with similar offerings include DTE Electric Company ("DTE") (approved), Duke Energy (proposed), Dominion Energy Virginia (proposed), and National Grid (proposed);

- Workplace Demand Response: Rocky Mountain Power's Power Balance and Demand Response to Optimize Charging at Intermodal Hub Project includes chargers with outputs up to 400 kW, to be installed at Utah Transit Authority's Intermodal Hub located in Salt Lake City, Utah. Other utilities with similar offerings include National Grid (approved) and New York State Electric & Gas Corporation (proposed);

- Bi-Directional Power Flow Demonstration: DTE's School Bus Pilot is testing similar capabilities and value streams from a customer and utility perspective. Other utilities with similar offerings include Consolidated Edison Company (approved) and Duke Energy in multiple states (proposed);

- Education & Outreach: Generally included in utility programs. With respect to the fleet electrification concierge concept, National Grid, through a combination of internal and third-party expertise, will offer a five-year Fleet Advisory Services Program to support electrification of customer fleets. The offering will include conducting fleet electrification studies for a total of 100 fleet operators in the Company's service territory, including public and private light, medium, and heavy-duty fleets, public transit including buses, and off-road vehicles such as fork lifts, seaport vehicles, and airport vehicles. Other utilities with similar offerings include Xcel Energy (approved) and Narragansett Electric (proposed); and

- Technical Development: Generally included in utility programs. Centered around data collection and managed charging, utilities are testing various approaches. National Grid R&D EV Charging Program will research managed charging through both the charging stations and direct communication with the vehicles.

Q. Is Consumers Energy working with other stakeholders in Michigan?

A. Yes, the Company has maintained strong stakeholder outreach, which started with PowerMIDrive, working with vendors, vehicle manufacturers, environmental organizations, and regulators to ensure that the Company is leveraging best practices to design a program that is suited for today's needs as well as able to expand into the future as the market grows.

The Company consulted a number of sources to determine Program design, including reviewing industry research and studies, interviewing charging and network providers and other utilities, utilizing internal subject matter experts, benchmarking against other existing and proposed programs, and utilizing learnings from PowerMIDrive.

V. PowerMIDrive 2019 Costs

Q. What are the program objectives and progress thus far for PowerMIDrive?

A. The primary objectives of PowerMIDrive are to incent residential EV owners to charge their vehicles at night, when it most benefits the grid, and to provide load profile data that will assist with refinements to managed charging options. Furthermore, PowerMIDrive aims to develop foundational infrastructure for EV charging across our service territory via DCFC and Level 2 public charging stations, and to learn from the load profiles of this infrastructure.

Q. Explain the status of the PowerMIDrive Program.

A. The PowerMIDrive Program is off to a strong start in 2019, with over 160 residential customers participating in the program, and all 200 Level 2 and 24 DCFC public charging stations reserved for applicants as of this filing. The residential charging stations are installed and functioning. Initial operation of public charging stations will largely occur in 2020 due to construction schedules. The Company emphasized the public charging infrastructure in 2019, knowing that applicants would need time to construct the facilities, and with the strategic viewpoint that public charging stations could help spur residential participation in the program via more convenient charging options.

Q. What was the PowerMIDrive spend for 2019?

A. The projected spend for 2019 is approximately $647,000. As of month-end October 2019, when data for this direct testimony was finalized, actual spend totaled $514,862.68, as shown in Exhibit A-91 (SRN-2). Further details are in Company witness Heidi J. Myers' direct testimony. Using monthly averages and projections, an additional $132,000 of expenditures is forecasted in November and December 2019. As required by the Commission, a formal report reflecting actual costs for PowerMIDrive's first year will be submitted to the Commission in the summer of 2020.

Q. What are the anticipated changes to PowerMIDrive in the second year of the Program?

A. Initial projections for the make-ready expenditures are coming in well below budget. For example, with a $2,500,000 initial budget, the 24 DCFC sites could each receive over $100,000 for make ready on average. However, initial make-ready estimates for the DCFC sites are averaging below $50,000. For Level 2s, the Company has not yet seen a case where a Level 2 public applicant required line upgrades. Given this, the Company plans to roll any cost saving from make-ready expenditures into new DCFC rebates and make ready fund opportunities. Utilizing this strategy, the Company anticipates that nearly 10 additional DCFCs (a potential of 34 instead of 24 DCFCs) may be achievable within the original PowerMIDrive budget of $10,000,000. The additional DCFCs are the most valuable addition to the program given their impact on foundational charging infrastructure, and the continued availability of VW settlement funds for applicants.

Q. Please explain Exhibit A-92 (SRN-3).

A. This exhibit is a comprehensive list of references used in this direct testimony and is provided for the convenience of the other parties to this case.

Q. Does this complete your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
______________________________	)	

DIRECT TESTIMONY

OF

PHILLIP M. RAUSCH

ON BEHALF OF

HEMLOCK SEMICONDUCTOR OPERATIONS LLC
AND
CONSUMERS ENERGY COMPANY

PUBLIC VERSION

February 2020

Q. Please state your name and business address.

A. My name is Phillip M. Rausch, and my business address is 12334 Geddes Road, Hemlock, Michigan 48626.

Q. What is your occupation?

A. I am a Business Development Manager for Hemlock Semiconductor Operations LLC ("HSC").

Q. Please briefly describe HSC.

A. HSC is a manufacturer of semiconductor and solar grade polycrystalline silicon and related chemicals headquartered in Hemlock, Michigan. HSC is a very large consumer of electric energy and is Consumers Energy Company's ("Consumers Energy" or the "Company") largest single site customer.

Q. Please describe your educational background and experience.

A. I graduated from Michigan Technological University with a Bachelor of Science degree in Chemical Engineering in 2008. I began working for HSC in 2008 as an engineer. Over time, I held positions of increasing responsibility within HSC, such as manufacturing team leader, economic evaluator, business finance analyst, and project engineering manager. In 2016, I graduated from Michigan State University with a Master's in Business Administration degree while working for HSC. In 2019, I rose to business development manager for HSC. In my current role, I am responsible for procurement of electricity and industrial gases for HSC's operations.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing as a joint witness for HSC and Consumers Energy in support of Consumers Energy's proposed Long-Term Industrial Load Retention Rate ("LTILRR") and associated LTILRR contract between Consumers Energy and HSC.

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

A. The purpose of my direct testimony is to address HSC's qualifications for an LTILRR contract under Public Act 348 of 2018, MCL 460.10gg ("Act 348"). Specially, I address HSC's average electric demand and average load factor at the time the contract was executed. I also address how HSC meets the statutory requirement that HSC would not purchase standard tariff service from Consumers Energy except under the LTILRR contract. Other statutory requirements supporting approval of the LTILRR are addressed by Consumers Energy's witness Michael P. Kelly.

I. Summary

Q. Please summarize your conclusions and recommendations to the Michigan Public Service Commission ("MPSC" or the "Commission").

A. My conclusions and recommendations can be summarized as follows:

1. HSC had an annual average electric demand of at least 200 MW at its Thomas Township, Michigan site at the time the LTILRR contract was executed on July 29, 2019;

2. HSC had an annual load factor of at least 75% at the time the LTILRR was executed on July 29, 2019; and

3. HSC meets the statutory requirement that it would not purchase standard tariff service from Consumers Energy except under the LTILRR by having entered the MISO generator interconnection queue with a generation resource that, if constructed, would qualify as self-service power of sufficient size to meet the LTILRR contract demand level.

II. <u>LTILRR eligibility</u>

Q. Please briefly describe Act 348?

A. Act 348 became effective on October 24, 2018. Act 348 authorizes the Commission to approve long-term industrial load rates for industrial customers. If proposed by an electric utility, either as part of a general electric rate case or in a stand-alone proceeding, the Commission is required to approve an LTILRR if the Commission finds that the proposed rate meets the enumerated requirements of Act 348. My direct testimony explains how HSC meets the statutory criteria in MCL 460.10gg(1)(c) that HSC would not purchase standard tariff service from Consumers Energy absent the LTILRR and associated contract.

Q. Please briefly describe the MCL 460.10GG(1)(C) Requirements.

A. MCL 460.10gg(1)(c) states as follows:

> (c) The proposed long-term industrial load rate requires that the industrial customer have an annual average electric demand of at least 200 megawatts at 1 site at the time the contract for a term is entered into, have an annual load factor of at least 75% at the time the contract for a term is entered into, and must demonstrate that the industrial customer would not purchase standard tariff service from the electric utility except under the long-term industrial load rate. The industrial customer demonstrates that it would not purchase standard tariff service from the electric utility except under the long-term industrial load rate if any of the following conditions exist:
>
> (i) The customer has available self-service power in a quantity equal to the contract demand level.
>
> (ii) The customer, or an entity acting on the customer's behalf, has entered the applicable regional transmission organization's generation interconnection queue for a new generation resource that, if constructed, would qualify as self-service power in a quantity equal to the contract demand level. Entering the applicable regional transmission organization's interconnection queue means compliance with all applicable interconnection application requirements, such as payment of the application fee, disclosure of the technical requirements, payment of the definitive planning phase studying

> funding deposit, demonstration of site control, and payment of all other applicable per-megawatt fees or deposits, as required by the regional transmission organization.

Thus, to qualify for the LTILRR, the customer must show: i) an annual average electric demand of at least 200 MW at one site at the time the contract is entered into; ii) an annual load factor of at least 75% at the time the contract is entered into; and iii) that the customer would not purchase standard tariff service except under the LTILRR. To show that the customer would not have purchased standard tariff service absent the LTILRR, the industrial customer must show either: i) that it has self-service power equal to the contract demand level; or ii) that it has entered the transmission organization's generator interconnection queue for a new generator that, if constructed, would qualify as self-service power in an amount equal to the contract demand level.

Q. Has HSC entered into an LTILRR contract with Consumers Energy?

A. Yes. On July 29, 2019, HSC executed an LTILRR special contract with Consumers Energy for service to HSC's site in Thomas Township, Michigan. A copy of the contract is filed in this proceeding as Consumers Energy's witness Kelly's Confidential Exhibit A-74 (MPK-2).

Q. Was HSC's annual average electric demand at least 200 MW at its Thomas Township, Michigan site as of July 29, 2019?

A. Yes. On July 29, 2019, HSC's average electric demand for its Thomas Township, Michigan site was [redacted].

Q. Did HSC have an annual load factor of at least 75% as of July 29, 2019?

A. Yes. On July 29, 2019, HSC's annual load factor was [redacted].

Q. What is the LTILRR contract demand level?

A. The LTILRR contract has a Maximum Contracted Capacity of 400 MW.

Q. Does HSC have self-service power in sufficient quantity equal to the contract demand level?

A. No. HSC does not have existing self-service power in an amount equal to the contract demand level. HSC satisfies the statutory requirement that HSC demonstrate that it would not purchase Consumers Energy's standard offer tariff service except under the LTILRR by having entered the applicable transmission organization's generator interconnection queue for a new resource under MCL 460.10gg(1)(c)(ii).

Q. What is the applicable regional transmission organization for service to HSC?

A. The applicable regional transmission organization for a new generation resource to serve HSC as self-service power at HSC's Thomas Township, Michigan site is the Midcontinent Independent System Operator, Inc. ("MISO").

Q. Did HSC enter MISO's generation interconnection queue for a new generation resource?

A. HSC contracted with Invenergy Development LLC ("Invenergy") to construct a new power plant at HSC's site in Thomas Township, Michigan. The new generation resource was to be owned by Invenergy for service to HSC. Invenergy, on HSC's behalf, entered the new plant in MISO's generator interconnection queue on June 16, 2017. The new plant was assigned generator interconnection queue number J841.

Q. Please describe the new generation resource?

A. The new generation resource was designed to be a 702 MW (Summer) / 725 MW (Winter) combined-cycle natural gas plant. The combined-cycle turbine power plant was comprised of two single shaft 1x1 blocks. Each block included a natural gas-fired combustion turbine operating in a combined-cycle configuration with a natural gas-fired heat recovery steam generating system and a steam turbine generator. The two 1x1 blocks comprised the combined-cycle power plant.

Q. If constructed, would the plant have served HSC as self-service power?

A. Yes. The new plant was designed to serve HSC's load at HSC's site in Thomas Township, Michigan on a behind-the-meter basis. The electricity would have been generated and consumed at HSC's Thomas Township's contiguous industrial sites without the use of either the transmission or distribution system.

Q. Is the proposed new generation resource still in MISO's generator interconnection queue?

A No. After HSC executed the LTILRR contract with Consumers, Invenergy removed the generation resource from MISO's queue. On September 11, 2019, the MPSC issued an order in Case No. U-20609 finding that withdrawal from the MISO queue by a customer who has entered into a long-term industrial load rate contract does not prohibit that customer and the utility from showing compliance with MCL 460.10gg(1)(c)(ii) in a later proceeding.

Q. At the time that the generation resource was removed from MISO's queue, was the resource in compliance with all applicable interconnection application requirements?

A. Yes. The proposed generation resource was in compliance with all MISO generator interconnection queue requirements at the time that it exited the queue. All applicable generator data for modeling, one-line interconnection drawings, $2.9 million letter of credit, demonstration of site control, and $0.5 million cash deposit were all submitted to

MISO as part of the interconnection application. Subsequently, as various study phases were completed, HSC maintained good standing in the project queue by answering questions that MISO had, confirming commitment of the project at each stage gate, and maintaining funding for the $2.9 million letter of credit. The proposed generation resource received from MISO its System Impact Study on February 21, 2019, its Phase 2 System Impact Study on April 26, 2019, and its Phase 3 System Impact Study on August 9, 2019.

V. <u>Conclusion</u>

Q. Please provide a brief summary of your direct testimony.

A. HSC meets the statutory criteria in MCL 460.10gg(1)(c) for approval of the LTILRR contract. HSC had an annual average electric demand of at least 200 MW at one site at the time the contract was entered into. HSC had an annual load factor of at least 75% at the time the contract was entered into. Further, HSC would not have purchased standard tariff service absent the LTILRR; HSC had entered MISO's generator interconnection queue for a new generator that, if constructed, would qualify as self-service power in an amount equal to the LTILRR contract demand level.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

LATINA D. SABA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is LaTina D. Saba, and my business address is 11801 Farmington Road, Livonia, Michigan 48150.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Facilities Manager of Transformation, Engineering, and Operations Support.

Q. What are your responsibilities as the Facilities Manager for Operations Support of Transformation, Engineering, and Operations Support?

A. I am responsible for the strategic alliance among Facilities Design, Space Management, and Operations within the Facilities Department. My responsibilities also include oversight of Facilities Management and Projects, Real Estate, and Administrative Operations.

Q. What is your formal educational experience?

A. I completed three years of a Construction Management program concurrently at Eastern Michigan University and Oakland Community College. Currently, I am completing my Bachelor of Science degree in Applied Management at Grand Canyon University. I hold and/or have held certificates in the following: a certificate issued by the Occupational Safety and Health Administration ("OSHA") for Construction Safety and Health training, a certificate issued by OSHA for Asbestos Awareness training, a certificate issued in Ontario for Basic Fall Protection training, and a certificate issued by 84 Lumber Company for its Management Basic Home Building course.

Q. Would you please describe your previous work experience?

A. In 2007, I worked as Project Engineer for Clark Construction Company based out of Lansing, Michigan. My projects included Retail, Healthcare, and Education sector projects, with special emphasis on safety, environmental protection, and profitability.

From 2009 until 2011, I worked in Canada as a Construction Office Manager for P.G. Aluminum Home Improvement in Brampton, Ontario, which specializes in residential construction aluminum building products and installation. In 2011, I took a position as the Assistant Construction Project Manager and Litigation Support for LB325 Bay Street for the Trump International Hotel & Tower, the largest skyscraper in Canada. The role required me to assist the Lead Project Manager of the 5,000-person site with responsibility for distribution of documents and materials; and for reviewing project estimates, contracts, bid packages and schedules, labor and materials cost forecasts, and monthly cost reporting. I assisted the superintendents of the project with monthly cost reports; expedited, reviewed and approved all shop drawings and submittals; documented as-built changes; and maintained records drawings, specifications, and distribution. I was also responsible for organizing and charting cost completion and man-hour forecasts, oversight of trade subcontractors, and recording and signing time and material sheets.

I returned to the United States in 2012 and began work as the Construction Area Manager for a non-profit organization where I assisted with the Playscape playground construction project in Wayne, Michigan. My responsibilities included grant writing, managing the construction budget, and the review, analysis, and decision-making surrounding issues of financial feasibility.

From 2012 until 2014, I was the Construction Project Manager for OSH, which is an international construction company where I restored the historic Pontchartrain Hotel. Under my management, the project was awarded the coveted title of "2013 Development of the Year" by the International Hotel Group ("IHG"). In this position, I also prepared and hosted events for the 2014 International North American Auto Show in Downtown Detroit. Due to unforeseen circumstances pending the 2014 International North American Auto Show, I was required to renovate three floors of ballroom spaces in two and a half days to accommodate the event. That project required me to assist the owner with feasibility studies, and provide field advice and product selections for architects, engineers, City of Detroit, IHG officials, and compliance officials. I was also responsible for negotiating, awarding, and overseeing contracts while hiring, training, and governing more than 60 employees and 35 different contractors. I further prepared schedules and cost impact analyses for possible delays.

In 2014, I was hired as the Construction Project Manager, on a contract basis, for Audu Engineering Consultants, which is a Michigan-based civil and structural engineering consultant company. I provided construction management services as an Owner's representative, which included contract administration, contract bidding, project scheduling monitoring, and cost control and analyses as a Quality Control/Quality Assurance Professional. The owner of the project was Consumers Energy. Consumers Energy subsequently hired me as an employee in 2015 as a Senior Business Support Consultant I in the Facilities Services Department, serving Distribution Operations and Engineering and Transmission, Generation Operation, and Shared Services.

I was promoted to Facilities Manager (Director of Facilities) in 2018, and I am responsible for the oversight of 63 facilities enterprise-wide. In my position, I am tasked every day with all necessary activities for the planning and implementation of safe, efficient, and competitive maintenance and operation of the Company's facilities. On a daily basis, I am actively engaged in a wide variety of business functions and processes throughout the Company. I routinely provide leadership and support for the planning, business analysis, general management, budget preparation and analysis, negotiations, transactions, customer services, and auditing of specific operating and support areas related to the Company's facilities. My duties fluctuate between projects, departments, and offices and I am directly involved in providing business analysis and support for plans, reports, impacts, contracts, schedules, estimates, data collection, observations, and field investigations related to those projects, departments, and offices within the Company.

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

A. Yes. I have sponsored testimony in the following MPSC cases:

Case No. U-20134	2018 Consumers Energy Electric Rate Case;
Case No. U-20322	2018 Consumers Energy Gas Rate Case; and
Case No. U-20650	2019 Consumers Energy Gas Rate Case.

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

A. My direct testimony will support Electric Operations Support. I will:

- Describe the Electric Operations Support function;
- Describe the methodology employed by Facility Operations ("Facilities") for evaluating the health of its various facilities;

- Support the reasonableness and prudence of the Operation and Maintenance ("O&M") expenses for Facilities, Real Estate, and Administrative Operations for the historical test year ended December 31, 2018, the bridge period beginning January 1, 2019, and ending December 31, 2020, and the projected test year ending December 31, 2021; and

- Support the reasonableness and prudence of the capital expenditures for Asset Preservation for the historical test year ended December 31, 2018, the bridge period beginning January 1, 2019, and ending December 31, 2020, and the projected test year ending December 31, 2021.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-12 (LDS-1)	Schedule B-5.6	Summary of Actual & Projected Electric and Common Capital Expenditures;
Exhibit A-93 (LDS-2)		Summary of Actual and Projected Operations Support O&M Expenses;
Exhibit A-94 (LDS-3)		Programs and Projects – Projected Electric and Common Capital Expenditures;
Exhibit A-95 (LDS-4)		Facility Assessment – Lansing Service Center
Exhibit A-96 (LDS-5)		Facility Assessment – Kalamazoo Service Center
Exhibit A-97 (LDS-6)		Facility Assessment – Hastings Service Center

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 (LDS-1), Schedule B-5.6, details the actual and projected capital expenditures related to Electric Operations Support. Exhibit A-93 (LDS-2) details the O&M costs related to Electric Operations Support. Exhibit A-94 (LDS-3) identifies

Electric Operations Support Projects and Programs and the projected capital expenditures related to those projects and programs. Exhibit A-95 (LDS-4) is the Facility Assessment of the Lansing Service Center utilized to evaluate the need for capital expenditures. Exhibit A-96 (LDS-5) is the Facility Assessment of the Kalamazoo Service Center utilized to evaluate the need for capital expenditures. Exhibit A-97 (LDS-6) is the Facility Assessment of the Hastings Service Center utilized to evaluate the need for capital expenditures.

Q. Please explain the Electric Operations Support function.

A. The Electric Operations Support consists of the following support organizations: Fleet Services, Facilities, Real Estate, and Administrative Operations. Electric Operations Support provides support by acquiring, constructing, and maintaining assets required to operate the functional areas of the business to serve our customers efficiently and effectively.

Q. Are you addressing all support organizations related to Electric Operations Support in your testimony and exhibits?

A. No. Fleet Services will be addressed in the testimony of Company witness Kyle P. Jones.

Q. What is the function of the Facilities organization?

A. Within Electric Operations Support, Facilities manages, maintains, and operates 63 buildings comprising 3.5 million square feet of building space across the state of Michigan that allow our co-workers to serve our customers across the state in the most efficient and effective manner.

Q. How have Company facilities changed over time?

A. The Company experienced major growth in the area of Facilities during the 1950s and 1960s. Of our 63 buildings, the majority were built or acquired during this period and remain in operation today; as a result, these building are now well over 50 years old.

Q. What structural concerns or problems do the Company's aging structures and facilities create for the Company?

A. Multiple major systems throughout these facilities, such as boilers, chillers, cranes, elevators, emergency generators, heating, ventilation, and air conditioning ("HVAC") systems, lighting, power distribution, paving, roofing, Uninterruptible Power Systems, and vehicle hoists are beyond their useful lives. Further, building materials in the facilities contain hazards such as asbestos and lead paint. Repairs on such aging infrastructure are not cost effective and can lead to lengthy projects and significant renovation or replacement of entire structures. It is increasingly difficult to identify adequate parts and obtain expertise to work on the aging equipment.

Q. What concerns or problems do the Company's aging structures and facilities create for the Company's workforce?

A. These aging structures no longer adequately accommodate the way work gets done to allow for collaboration and efficiency in the space. The needs of the Company's workforce have changed significantly since the 1950s and 1960s (i.e. there is a greater need for open office environments, collaborative work group spaces, computers in the workplace, internet and wireless communication networks, etc.).

Q. What concerns or problems do the Company's aging structures and facilities create for the Company's customers?

A. The population and infrastructure of the state of Michigan look much different than they did in the 1950s and 1960s. The location of some of our facilities no longer allows the Company to optimize service to customers. Longer response times and increased drive times make meeting service delivery standards difficult for the Company's employees who are dedicated to providing the best service to Consumers Energy's customers.

Q. What process does Consumers Energy utilize to evaluate whether or not to make capital investments in facilities?

A. A formal assessment process was established in 2016 to determine the need for capital investments in facilities. The Facilities department has experts in HVAC, plumbing, electrical, etc., that conduct the assessment. In that process, an evaluation is made, on a multi-category scale, of certain conditions and characteristics of the structure and functions of the facility being assessed. For each facility, each condition and characteristic is scored (with a possible score of 1 to 5 per category), and then the facility is ranked on a multi-category scale (with a 75-point maximum score).

Q. What categories are included in the evaluation process of the Company's facilities?

A. Categories that are evaluated include: (i) safety (asbestos or other hazardous materials, traffic flow, compatibility with surrounding areas, etc.); (ii) quality (workplace efficiency, employee comfort, employee attraction and retention, etc.); (iii) cost (facility operating costs, space optimization, energy efficiency, etc.); and (iv) delivery (response times, driving distance within service territory, sustainability of operations, etc.).

Q. How is the quality of the categories identified above established?

A. The facility evaluated will fall within one of three quality designation categories depending on the score received. A score of above 60 is designated as "Good"; a score of 30 to 60 is designated as "Serviceable," meaning that investment is needed; and a score under 30 is designated as "Poor," meaning that there are multiple systems failing at the facility.

Q. What is the next step in the facility assessment?

A. Once the facility is initially evaluated and receives a quality designation, operational departments of the business then review and validate the raw scored ranking, and adjust the ranking to reflect forecasted needs of the business. Facilities finalizes the score, and any facility that scores below a minimum acceptable level, 60 out of 75 points, is targeted for renovation or replacement.

Q. What is the purpose of the evaluation process?

A. The intent of the evaluation or assessment process is to prioritize facilities for investments to bring the score, or quality designation, for each Company facility within an acceptable range (60 to 75 points). The cost to bring a facility within the acceptable range can vary greatly. There are numerous factors involved such as size and scale of an individual facility, the extent of the renovation/redesign needed, etc. For example, the Benzonia Service Center has approximately 5,698 square feet of space versus the Kalamazoo Service Center which has approximately 140,884 square feet of space. These factors greatly impact the associated investment required to renovate or replace individual facilities. The differences in required level of investment lead to differences in the annual investment required to perform renovation or replacement work.

Q. What projects are included in the projected capital expenditures for Facilities?

A. There are approximately 21 separate projects which contribute to the projected Facilities capital expenditures for the 24-month projected bridge period ending December 31, 2020 and 12-month projected test year ending December 31, 2021. These projects are identified on Exhibit A-94 (LDS-3).

Q. Please describe the capital expenditures set forth on Exhibit A-12 (LDS-1), Schedule B-5.6.

A. As demonstrated on Exhibit A-12 (LDS-1), Schedule B-5.6, capital spending is divided into two programs: Asset Preservation, and Computer and Other Equipment. Asset Preservation is then broken down into multiple cost categories including contractor, labor, materials, business expenses and other (loadings, chargebacks). The majority of capital spending, as reflected on Exhibit A-12 (LDS-1), Schedule B-5.6, is for Asset Preservation, which encompasses the Company's facilities investments.

Q. Please generally explain the types of Asset Preservation facilities investments that are included in the projected costs for the projected test year ending December 31, 2021.

A. Asset Preservation of the Company's facilities investments generally includes new construction, remodeling of existing facilities, emergent work, lifecycle replacement of infrastructure equipment, and system failures. The estimated costs are based on current construction estimating and planning with the known requirements. These estimates can vary as changes to the scope, initial design, materials, or possible unseen issues arise, such as environmental remediations.

Q. What categories of facilities investment are included in the Company's Asset Preservation?

A. The Company's Asset Preservation of facilities investments includes: (i) infrastructure investments; (ii) upgrades and maintenance; and (iii) purchase, new construction, and renovations. These facilities investments allow for the Company to be strategically placed in order to safely and efficiently respond to customers' requests.

Q. What capital expenditures are included in "infrastructure investments"?

A. Infrastructure investments include removing conditions that contribute to potential health and safety hazards, proactively repairing emergency backup systems, and repairing failed capital components of buildings, which are comprised of: yards, grounds, building envelope and operating systems. These minimal facilities infrastructure investments mitigate the effects of building depreciation to avoid imminent near-term failures and upgrades for health and wellness.

Q. What capital expenditures are included in "upgrades and maintenance"?

A. Upgrades and maintenance capital expenditures include capital expenditures such as those made to parking lots, roofs, and elevators at various building and plant sites.

Q. How are "upgrades and maintenance" projects targeted?

A. Condition assessments are performed on a regular basis, for example a portion of roof sections are inspected annually such that all roofs are inspected once every three years, and a portion of paving sections are inspected annually such that all paving is inspected once every five years. The condition of each assessed asset is ranked following standard industry recognized methodologies, those assets assessed to be below acceptable condition are targeted for renovation or replacement.

Q. What capital expenditures are included in "purchase, new construction, and renovations"?

A. The final component of the facilities investment plan is the purchase, new construction, and/or renovation of service centers and other buildings to support operations across the state of Michigan.

Q. Are these types of Asset Preservation projects identified in Exhibit A-94 (LDS-3)?

A. Yes. The proposed Asset Preservation projects are identified in Exhibit A-94 (LDS-3), lines 7 through 27.

Q. What are the major Asset Preservation projects that are planned?

A. Major Asset Preservation projects planned for Facilities include the construction of the Lansing Service Center, Kalamazoo Service Center, Hastings Service Center, Circuit 501, and land acquisition for future construction of a hardened Unified Control Center ("UCC") facility.

Q. Does the Company consider environmental impacts when planning for the construction and/or renovation of a structure or building?

A. Yes. New buildings are constructed to meet the United States Green Building Council ("USGBC") standards (see usgbc.org), and the Leadership in Energy and Environmental Design ("LEED") standards, (see usgbc.org/leed), with specific emphasis on reduced energy consumption, sustainability and reduced operating cost.

Q. Do these environmental building standards benefit the Company's customers?

A. Yes. When compared to conventional construction, buildings designed to LEED standards reduce lifetime energy consumption by 30% or more, resulting in reduced operational costs which allow our 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 less O&M costs, estimated at a 5% reduction.

Q. Please describe the Lansing Service Center project?

A. In this project, the Company is purchasing land in a new location and constructing a new facility on that property. This facility will allow the Company to retire use of its existing facility (which will be demolished and retained to address and abate environmental concerns related to the property). This new facility will house all employees currently working out of the existing service center, which primarily includes electric operations and customer operation including a contact center.

Q. Why has the Company chosen to build a new Lansing Service Center?

A. As demonstrated on Exhibit A-95 (LDS-4), a Facilities assessment of the existing Lansing Service Center produced a score of 28. As discussed above, this placed the existing Lansing Service Center in the quality designation of "Poor." As reflected in the scores set forth on Exhibit A-95 (LDS-4), there are a number of reasons that 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 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. At this time, these systems require substantial renovations/replacement. Additionally, the existing service center is located in a residentially-zoned neighborhood and, due to the location, does not allow electric operations to meet customer needs in a timely fashion. Further, the roads (because of the residential zoning) are inadequate for the size of equipment utilized in and out of the service center and there are often children in the vicinity, which creates significant safety concerns. The current site is also located within the floodplain of the Grand River with the finish floor elevation being located 3 feet below the major flooding elevation projected by FEMA. Other considerations supporting the decision to construct a new facility rather than renovate the existing facility include security and environmental abatement.

Q. **Can you elaborate further on the security and environmental abatement issues at the Lansing Service Center?**

A. Yes. The site has experienced multiple law enforcement incidents some involving the pursuit of armed suspects across and through the property, including areas within the secured perimeter. These incidents have resulted in lock-down safety protocol implementation for employees and a resulting general level of unease regarding the safety and security of employees, customers, and others, while on the property and when accessing or leaving the property. Environmental issues arise from the former use of the current Lansing Service Center site as the location of a former Manufactured Gas Plant ("MGP") regulated under Part 201 of State of Michigan Act 451 of 1994. This site has historical environmental contamination issues resulting from operation of the MGP, including significant underground impacted soil materials (coal tar residual, etc.). Additionally, the facility contains asbestos insulation for pipe and duct work, asbestos flooring and has significant areas of lead paint in poor and peeling condition. Given these environmental issues, upgrades to the facility are not feasible (such as carpet replacements and open space enhancements).

Q. The Lansing Service Center project includes the relocation of that facility. Can you explain what is considered generally when considering relocation of a facility?

A. Yes. As I previously discussed, Company facilities are assessed and scored based on multiple criteria (safety, quality, cost, delivery, etc.) to provide a holistic score that informs the Company of the possible need to make investments to make improvements. Facilities with scores falling below the acceptable range are targeted for renovation or replacement. Part of the overall analysis, which is relevant to the Lansing Service Center, is the geographic location of targeted facilities. Geographic locations are analyzed against Customer workload distribution within the service territory to determine optimal location for the facility. Facilities that are determined to be mis-located within the customer service territory are evaluated for relocation to a newly constructed site, with the goal of improved customer response. Facilities determined to already be optimally located with the customer service territory are evaluated for renovation or reconstruction on the existing site.

Q. How did the Company determine a new location for the Lansing Service Center?

A. An analysis of customer distribution across the service territory where the Lansing Service Center is located, and potential service center locations within that service territory, determined the optimal area to minimize response times and maximize employee efficiency, which required the relocation of that facility. The current location of the Lansing Service Center is offset to the north and east of the optimal location, in a residentially-zoned neighborhood, and the current location does not provide readily available highway access. The current location of the Service Center within the service territory results in increased customer response times and reduced employee efficiency due to increased travel times. The location for the new Lansing Service Center will provide both improved customer response times and employee efficiency.

Q. What benefits will this new Lansing Service Center offer?

A. The new Lansing Service Center will benefit customers by lowering operational costs, providing better response times to electric customers, and will be in a more compatible location which is properly zoned for industrial use, minimizing safety concerns.

Q. Please describe the Kalamazoo Service Center project?

A. In this project, the Company is constructing a new facility on the existing property. Upon completion of the new facility, the Company will retire, demolish and remediate environmental concerns at the existing facility.

Q. Why has the Company chosen to construct a new facility on the existing Kalamazoo Service Center site?

A. As demonstrated on Exhibit A-96 (LDS-5), a Facilities assessment of the existing Kalamazoo Service Center produced a score of 45. Since this assessment was conducted, additional asbestos issues have been identified at this site (i.e. spray applied fireproofing, pipe wrap, floor tiles, etc.). All of the employees at this site have had to be moved to the 2nd floor due to the asbestos concerns on the 1st floor. This limited space is inadequate to operate for our Electric Operations partners. As discussed above, because this score falls below a score of 60, it was targeted for replacement. In addition to the environmental concerns, the existing Kalamazoo Service Center was constructed in 1965, and its continuing use is inadequate for a number of reasons relating to aging infrastructure. Most of the existing systems throughout the facility are now over 50 years old and beyond their useful life. Finally, the space requirements of the existing workforce have significantly changed, requiring open office environments, collaborative work groups, computer technology in the workplace, and the need for internet and wireless communication networks all support the need for a newly constructed rather than renovated facility. Because the Kalamazoo Service Center is optimally located for responding timely to the Company's customers, however, the new Kalamazoo Service Center will be constructed on the existing site.

Q. What are the benefits of the new Kalamazoo Service Center?

A. This service center will have a new energy-efficient building constructed (with demolition of the old building taking place after all employees have been moved to the new location), and will have a new storm-retention system (the previous water system discharges into the city sewer system). Customers will benefit from reduced operational costs as energy and work space efficiencies are achieved.

Q. Please describe the Hastings Service Center project?

A. Like the Kalamazoo Service Center, in this project, the Company is constructing a new facility on the existing property.

Q. Why has the Company chosen to construct a new Hastings Service Center facility?

A. As demonstrated on Exhibit A-97 (LDS-6), a Facilities assessment of the existing Hastings Service Center produced a score of 34. As discussed above, and like the Kalamazoo Service Center, because this score falls below a score of 60, it was targeted for replacement. For the same reasons that the Lansing Service Center and Kalamazoo Service Center were targeted for replacement, including aging infrastructure which is beyond useful life, the Hastings Service Center was determined to need replacement.

Q. Can you quantify the expected reduction in annual O&M expense associated with the construction of the new service centers?

A. Yes. I would expect that annual operating expenses would be reduced by 5% once the new facilities are in operation, which will include energy consummation reductions and maintenance operations savings.

Q. How is the anticipated 5% reduction in operating expenses to be achieved?

A. Primarily the savings will result from improved energy efficiency of the facilities. The buildings will be constructed to LEED environmental standards with a goal of achieving a minimum reduction of 30% for energy consumed by the buildings annually when compared to buildings utilizing standard construction. Additionally, when compared to older facilities, new building systems require less maintenance and repairs. These factors, taken in combination, are anticipated to yield the 5% reduction in overall operating costs for the service centers.

Q. Please describe the UCC project.

A. This project involves the construction of a new hardened facility to consolidate various functions of other facilities in a centralized location which will allow consolidation of control and management functions for the electric grid, merchant operations, and gas control. This building will be constructed to allow management of the electric operations workforce as that workforce responds to electric customer outages and performs storm restoration work throughout the state. This site will consolidate two system control centers (Grand Rapids and Jackson) and three dispatch centers (Saginaw, Grand Rapids, and Jackson).

Q. Why is this consolidation of facilities to a more central facility beneficial?

A. The UCC will allow for, in part, increased safety for the Company's workforce and customers, and will also provide for better-coordinated and faster emergency response, providing a faster resolution for incidents needing immediate attention. Currently, control, planning, and dispatch functions are spread across four locations and multiple spaces within each location. This results in difficulty and inefficiency in coordinating work in the same area and on the same circuit, and further increases the risk of serious safety incidents and extended outage durations relating to operation of grid components. The UCC's proposed centralized grid control facility would alleviate these problems and is currently the industry standard best practice. Consumers Energy is one of only a few remaining utilities that does not utilize a UCC. Business case support and further information regarding the UCC project is provided by Company witness Brenda L. Houtz.

Q. Please describe the Circuit 501 Project.

A. The Circuit 501 Project is a new facility that is intended to be a multi-use facility located in a part of Michigan that is geographically accessible and used by Company employees state-wide. This proposal is in its early stages and is intended, in part, to be utilized as a learning and development center that will draw employees from all parts of the state and provide more centrally-located training opportunities to employees at all levels of the Company. This space will promote the initiatives of the Company related to the evolution of business practices and work environments (both culturally and physically) which ultimately promotes the delivery of safe, reliable, and affordable energy to the Company's customers. The new facility construction project will enable the Company's ability to deliver on our commitment to the State's economic growth, assist with talent acquisition and retention of present and future Consumers Energy employees, and showcase to the business community the effectiveness of energy conservation construction which is a key element of continued energy waste reduction success that enables sustainability for the State. This is consistent with the Company's Commission-approved IRP. This facility will house employees and will be constructed in a manner that will promote and demonstrate innovative generation, distribution, resiliency, and storage also consistent with the IRP.

Q. What other projects are included in the projected bridge period ending December 31, 2020 and projected test year ending December 31, 2021?

A. As demonstrated on Exhibit A-94 (LDS-3), additional projects include projects such as the ongoing Parnall Road Complex renovation, statewide roofing, and Energy Resources Asset Preservation.

Q. What was the Company's capital expenditure amount in the historical test year ended December 31, 2018?

A. As depicted in Exhibit A-12 (LDS-1), Schedule B-5.6, line 8, capital expenditures for the historical test year ended December 31, 2018, totaled $26.247 million. The projects completed in 2018 include the new construction of the new Coldwater Service Center, renovation of Parnall P1-1, and renovation of the Saginaw Customer Contact Center (call center).

Q. Please describe the capital expenditures related to Computer and Other Equipment for Electric Operations Support as shown on Exhibit A-12 (LDS-1), Schedule B-5.6, line 7.

A. Computer and Other Equipment includes the purchase of miscellaneous printers, mechanical equipment, print production equipment, and wellness equipment. These expenditures are depicted in Exhibit A-94 (LDS-3), lines 1 through 6.

Q. What is the Company projecting for project capital spending related to Electric Operations Support?

A. As depicted in Exhibit A-12 (LDS-1), Schedule B-5.6, line 8, capital expenditures are projected to be $20,740, 000 for the 12 months ending December 31, 2019; $21,774,000 for 12 months ending December 31, 2020; and $64,856,000 for 12 months ending December 31, 2021, for a three year total of $107,370,000.

Q. Does Electric Operations Support also have projected O&M expenses?

A. Yes, As shown in Exhibit A-93 (LDS-2), Electric Operations Support operations include O&M for all Company electric-related facilities work, real estate services, and administrative operations.

Q. What O&M expenses are included in "facilities work"?

A. Facilities work includes items such as maintenance and repair of heating, air conditioning, and ventilation systems; miscellaneous building repairs, yard maintenance and snow removal; and daily cleaning or other major scheduled cleaning projects such as windows and carpeting.

Q. What O&M expenses are included in "real estate services"?

A. Real estate services includes a variety of real estate asset management functions to ensure system integrity and safeguard the public. This includes management of all land related uses of easements and rights of way, including encroachments, third party requests for use of our property, land owner 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 system for property ownership and rights of way.

Q. What O&M expenses are included in "administrative operations"?

A. Administration Operations assists with administration support services for Consumers Energy's Security Command Center, Information Technology, Help Desk, Human Resources, Corporate Safety and Health, Fleet, Facilities, Supply Chain, Learning and Development, Real Estate, Travel Services, Operating Maintenance and Construction Jobline, and its Mail services. This assistance includes intake and scheduling of maintenance work, scheduling of maintenance staff, vendor and contractor management, purchasing of materials and services, document reproduction, and internal mail distribution.

Q. What is the calculated O&M expense for Electric Operations Support displayed on Exhibit A-93 (LDS-2), line 4?

A. The O&M expense reflected in the projected test year ending December 31, 2021, totals $17,065,000 and is shown on Exhibit A-93 (LDS-2), line 4, column (e).

Q. Does this conclude your direct testimony in this proceeding?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

CHRIS A. SHELLBERG

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Chris A. Shellberg, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

QUALIFICATIONS

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 High Voltage Distribution ("HVD") and Forestry Management. The Forestry Operations Department ("Forestry") is the department under HVD and Forestry Management that manages the line clearing of the Company's electric system.

Q. Please describe your educational background and work experience.

A. I am the Executive Director of HVD and Forestry Management for Consumers Energy. I have 23 years of utility experience at Consumers Energy, holding several operational leadership roles, previously as the Executive Director of Low Voltage Distribution ("LVD") West/Electric Meter Operations/Customer Field Solutions. Over the last 10 years, I have held the roles of Executive Director of Electric Construction, Executive Manager of Operations Services, and the Director of Metering Technology and Development. I am skilled in distribution lines and substation construction, service restoration, metering, process engineering, smart grid engineering, as well as financial management. I hold a Bachelor of Science Degree in Electrical and Electronics Engineering from Western Michigan University.

Q. What are your responsibilities as Executive Director of HVD and Forestry Management?

A. I have responsibilities for all Forestry functions including line clearing, budgeting, planning, and operations for the Company's distribution system. I also have responsibilities for maintenance and construction work for HVD lines, as well as all new construction and maintenance of 1300 plus substations at Consumers Energy. In addition, the Substation Operations and Electric Field Lab groups are within my reporting responsibilities.

PURPOSE OF DIRECT TESTIMONY

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

A. The purpose of my direct testimony is to support the Company's request in this case for an increase in funding for its Line Clearing Program.

EXHIBITS

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

A. Yes, I am sponsoring the following exhibits:

Exhibit A-98 (CAS-1)	Line Clearing O&M Expense;
Exhibit A-99 (CAS-2)	Line Clearing Ramp-up Plan Estimated Service Restoration Reductions;
Exhibit A-100 (CAS-3)	2021 HVD Line Clearing Work Plan;
Exhibit A-101 (CAS-4)	Line Clearing Reliability Results; and
Exhibit A-102 (CAS-5)	Justification of 7-year Cycle VS Other Cycles.

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

A. Yes.

LINE CLEARING

Q. Please explain the Company's Line Clearing Program.

A. The Company's Line Clearing Program is responsible for maintaining clearance between vegetation and energized equipment and to eliminate vegetation hindering accessibility to the Company's electric lines. The Company uses Integrated Vegetation Management ("IVM") along the Company's electric line rights-of-way to accomplish these objectives. IVM is the practice of promoting compatible plant communities along rights-of-way through the use of a combination of cost-effective methods including: chemical, cultural, mechanical, or manual treatments. The Line Clearing Program is divided into two programs based on system voltages: (i) LVD line clearing, and (ii) HVD line clearing.

Q. Please describe the Company's LVD Line Clearing Program.

A. The Company's LVD Line Clearing Program manages vegetation along its primary voltage systems and its secondary voltage systems, including service conductors. The Company clears vegetation within a 30-foot-wide right-of-way for primary voltages to attain a minimum of 10 feet of separation between conductors and vegetation at the time of clearing, and to maintain accessibility along the right-of-way for maintenance and repair of the line. As a part of scheduled maintenance line clearing, hazard trees (such as dead or dying trees that are within 20 feet of the edge of the right-of-way that are accessible to aerial lift trucks) are removed when not objected to by the property owner.

The Company's LVD Line Clearing Program consists of several sub-programs including: (i) program maintenance (full circuit clearing); (ii) repetitive outage zonal clearing; (iii) first zone clearing; (iv) brushing and herbicide treatments; (v) demand clearing (customer requested work); and (vi) Customers Experiencing Multiple

Interruptions ("CEMI") clearing. This new sub-program called CEMI clearing is being added in 2020 to focus on customers experiencing large numbers of outages within a 12-month timeframe.

Q. Please describe the Company's HVD Line Clearing Program.

A. The HVD Line Clearing Program manages vegetation along the Company's high voltage systems. There are two major voltages on the Company's HVD system: (i) 46 kV, and (ii) 138 kV. The Company clears vegetation within an 80 to 120-foot-wide right-of-way for these voltages to attain a minimum of 15 feet of separation for 46 kV lines and 20 feet of separation for 138 kV lines, between conductors and vegetation at the time of clearing. The Company also manages vegetation within the right-of-way to maintain accessibility along the right-of-way for maintenance and repair of the line. During scheduled maintenance line clearing, the Company identifies and removes hazard trees up to 40 feet from the edge of the right-of-way. The Company's HVD Line Clearing Program includes these sub-programs: (i) maintenance tree clearing; (ii) brushing and herbicide treatment; (iii) demand clearing; and (iv) noxious weed control (grass and weed mowing to meet local ordinances).

Q. Why is line clearing important to the Company?

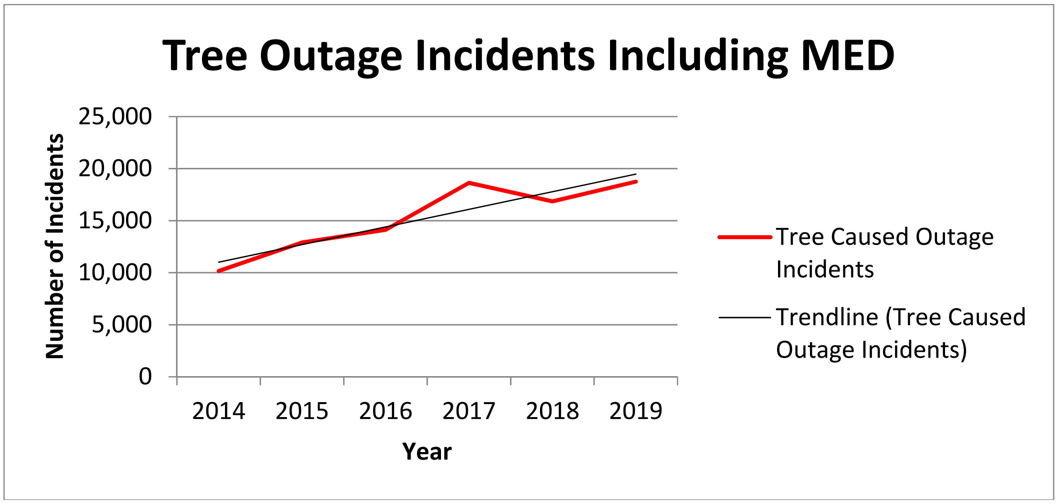
A. Trees are the greatest cause of interruptions to electric service to the Company's customers on the LVD system, and a significant cause of outages or interruptions of electric service on the HVD system. Figure 1 below shows the history of tree-caused interruptions affecting customers from 2014 through 2019 including: (i) the number of interruption incidents; (ii) customers interrupted; and (iii) customer minutes of outage for tree-caused outages to the LVD and HVD systems. Figure 2 below shows the trend of tree-caused outage incidents from 2014 through 2019 including Major Event Days ("MEDs"). In this timeframe, outages due to tree contact have almost doubled, and continue to trend higher at current funding levels. The Company's Line Clearing Program is designed to minimize these occurrences, improve reliable service to customers, and decrease reactive maintenance and capital expense associated with interruptions during weather events. Enhancing the ability of the Company to clear more miles of circuits each year will further improve reliability of service and decrease the potential impacts and costs of weather events to the LVD and HVD systems.

The Company's Line Clearing Program also provides benefits not easily quantified, such as improved habitat for many plants and animals (including threatened and endangered species) and decreased risk of wildfires from tree contacts with conductors. Enhancing the Company's Line Clearing Program will ultimately result in less aesthetic trimming impacts to customer properties and will improve public safety. These benefits support the Company's strategic triple bottom line goal of people, planet, and prosperity.

Figure 1
Tree-Caused Reliability Metrics 2014 through 2019 Including MEDs

	2014	2015	2016	2017	2018	Projected 2019
Incidents	10,169	12,912	14,125	18,634	16,860	21,853
Customers Interrupted	537,259	641,858	779,092	1,015,300	872,675	1,164,156
Customer Minutes	235,806,071	349,903,524	235,006,293	621,000,968	386,875,285	696,760,006

Figure 2
2014 through 2019 Projected Tree-Caused Outage Incidents on the LVD and HVD Systems



Q. What is the Company's strategy for its Line Clearing Program?

A. In this filing, the Company is proposing a significant increase in spending for its LVD Line Clearing Program starting in the 2021 test year. The purpose of this increase is to ramp up the miles of LVD circuits cleared every year in an efficient manner until one-seventh of the total LVD mileage is cleared in 2025, and then to maintain that level of clearing each year thereafter to bring the LVD system to an effective seven-year clearing cycle. The HVD Line Clearing Program is currently on a four-year clearing cycle and the Company proposes to maintain that level of clearing.

Q. What level of spending is the Company proposing for the 2021 test year for its Line Clearing Program?

A. As discussed below in greater detail under each program of my direct testimony, the Company is proposing to spend $84 million on line clearing in the 2021 test year, as shown in Figure 3 below:

FIGURE 3
LINE CLEARING EXPENSES, 2021 TEST YEAR

Categories	Expenses
LVD Line Clearing	$65,400,000
HVD Line Clearing	$11,750,000
Line Clearing Admin	$6,850,000
Total	**$84,000,000**

Q. Please describe the line item in Figure 3 titled "Line Clearing Admin."

A. Line Clearing Admin is the internal salaries and expenses of the Forestry personnel that plan the work, interact with customers, administer the contracts, and oversee the performance of the Company's line clearing contractors. This amount is reflected in Exhibit A-98 (CAS-1), lines 8, 9, 18, and 19, column (h).

Q. What impact does the proposed increase have on the Company's projected spending on line clearing beyond the 2021 test year?

A. The Company's proposed spending of the LVD Line Clearing Program increases in 2022 through 2025, to reach an expense level that permits clearing approximately one-seventh of its LVD line miles annually. The Company will then maintain that level of clearing in subsequent years in order to complete a seven-year effective cycle for the LVD Line Clearing Program. The Company's overall proposed line clearing spending beyond 2021 is shown in Figure 4 below:

FIGURE 4
LINE CLEARING EXPENSES, 2022 THROUGH 2025

Year	LVD Line Clearing	HVD Line Clearing	Line Clearing Admin	Total
2022	$74,985,000	$12,000,000	$7,340,000	$94,325,000
2023	$79,540,000	$12,300,000	$8,160,000	$100,000,000
2024	$95,600,000	$12,600,000	$9,380,000	$117,580,000
2025	$98,020,000	$12,900,000	$9,405,000	$120,325,000

<u>LVD LINE CLEARING</u>

Q. Please explain what projects, activities, and other types of work will be funded by spending in the LVD Line Clearing Program.

A. The Company's LVD Line Clearing Program consists of six categories of work: (i) program maintenance (full circuit clearing); (ii) repetitive outage zonal clearing; (iii) first zone clearing; (iv) brushing and herbicide treatments; (v) demand clearing (customer requested); and (vi) CEMI clearing.

Q. Does the Company's LVD Line Clearing Program include clearing required for service restoration?

A. Forestry is a key piece of the Company's service restoration efforts. Forestry manages the line clearing crews during restoration events, working together with many other areas of the Company to restore service or address emergent threats to the system. The costs for this work is captured in the service restoration budget addressed by Company witness Brenda L. Houtz, and is not a part of the line clearing funding discussed in my direct testimony. However, the funding requested for line clearing establishes a base of line clearing crews working on the system that are utilized for service restoration work when needed.

Q. What does full circuit clearing entail?

A. Full circuit clearing is the primary scheduled maintenance clearing work for the LVD system. This work is performed by contractors with qualified line clearance tree trimmer employees, in accordance with Michigan Occupational Safety and Health Administration requirements, on production-oriented contracts with the Company. Trees are cleared to attain at least 10 feet of clearance to primary conductors. Secondary voltage conductors and services are cleared of any tree limbs displacing or rubbing on these conductors. Brush (sapling trees and woody shrub species) are cut within the 30-foot right-of-way. Hazard trees (dead, dying, or mechanically stressed trees) standing outside of the right-of-way, but within 20 feet of the edge of the right-of-way, are removed when not objected to by the property owner.

Q. What is entailed in repetitive outage work?

A. Repetitive outage work clears specific sections of circuits to Load Concentration Points ("LCPs") that are experiencing high levels of tree-caused outages. LCPs are fuses, switches, or reclosures that isolate outages within an LVD circuit. Monthly, the Company reviews sections of circuits for multiple, tree-related, non-MED outages within the previous 12 months. Identified sections are scheduled for clearing based on system reliability impacts and resource limitations.

Q. What is entailed in first zone work?

A. First zone work clears the section of a circuit from the substation outward to logical load control points. Typically, these are three-phase structures (poles with X, Y, and Z phasing) and any unfused laterals that tap off of 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 on the circuit.

Q. What is entailed in brushing and herbicide treatments?

A. Brush control uses herbicide applications to treat brush within the right-of-way two to three years following full circuit clearing, particularly on rural and suburban circuits with higher brush densities in the right-of-way. This work reduces future stem volume, 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 is entailed in demand work?

A. Demand work addresses emergent vegetation threats to the LVD system. Emergent vegetation threats are identified predominantly by customers calling in personal observations around their homes, from Forestry personnel, and from other electric operations employees performing duties in the field. The Company's Forestry personnel review these requests in person, or through phone conversations, with the reporting party to validate the emergent nature and the likelihood of an outage. Work that can wait until maintenance clearing will be performed is delayed, but validated threats to the system are addressed based on system reliability impacts and resource limitations.

Q. What does the CEMI clearing work entail?

A. CEMI clearing work is designed to target customers experiencing high numbers of outages over the previous 12-month period and reduce the likelihood that these customers will experience similar outages going forward. CEMI clearing differs from repetitive outage 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 to a particular LCP. For CEMI, no one particular LCP may be experiencing outage rates at the repetitive outage metric but the cumulative effect of multiple upstream devices, each with just a few outages, results in the customer having many outages. CEMI clearing targets selective areas upstream of the customer location to reduce future outages.

Q. Please explain the effective seven-year cycle and how it works.

A. The Company utilizes three major primary voltages on the LVD system. Each of these voltages have unique tree-caused outage characteristics. To optimize the number of outages occurring on the system, each voltage has a desired cycle of clearing (the 14.4/24.9 kV circuits have the shortest cycle, and the 4.8/8.32 kV circuits have the longest cycle). Using the miles of each voltage class on the system and the optimal cycle for each voltage, the "average" cycle length is seven years, or 14% of system miles as shown in Figure 5 below. The average miles of each LVD voltage class requiring clearing every year under an optimal seven-year effective cycle are shown in Figure 5 below. Exhibit A-102 (CAS-5) details the calculations, based on historic actual data, used to show that the seven-year effective cycle is the most cost-beneficial approach to reducing tree-related outages on the LVD system at current system conditions. It includes several charts showing the average performance of each voltage class and the cost to clear an average mile of right-of-way based on the number of years since last clearing. Exhibit A-102 (CAS-5), line 19, shows the cost-benefit of the effective seven-year cycle ($11,412 per reduced outage incident) to be better than a five-year cycle for all voltages (Exhibit A-102 (CAS-5), line 21, shows $14,496 per reduced outage incident) and all other alternatives reviewed in the analysis.

FIGURE 5
LVD CLEARING SCHEDULE FOR A SEVEN-YEAR EFFECTIVE CYCLE

Voltage Group	System Miles	14% Clearing Program – miles/year cleared	Effective Cycle for Voltage Group
14.4 kV	17,310	3,462	5 years
7.2 kV	9,891	1,413	7 years
4.8 kV	31,380	3,487	9 years

Q. What is the Company's projected 2021 test year spending level for which it is requesting cost recovery in the LVD Line Clearing Program?

A. The Company is projecting LVD line clearing expenses of $71,430,000 in the 2021 test year, as shown in Figure 6 below, and in Exhibit A-98 (CAS-1).

Q. How would these projected expenses be allocated among the categories of work described above?

A. The Company is projecting expenses in the test year for each category as identified in Figure 6 below:

FIGURE 6
LVD LINE CLEARING EXPENSES

Categories	Expenses	Line Miles
Full Circuit Clearing	$54,265,000	4,465
Repetitive Outage	$2,000,000	99
CEMI Clearing	$3,125,000	154
First Zone Clearing	$1,875,000	150
Demand Work	$1,235,000	27
Brush Control	$2,900,000	328
Line Clearing Admin	$6,030,000	n/a
Total	**$71,430,000**	**5,223**

Q. What spending level for the LVD Line Clearing Program was approved in the Company's last electric rate case order?

A. The Michigan Public Service Commission ("MPSC" or the "Commission") approved a settlement among the parties in the Company's 2018 Electric Rate Case No. U-20134. The parties agreed to a $53 million Line Clearing Program spending commitment by the Company for calendar year 2019. This amount was in line with the Company's filed line clearing spending level in that case, which consisted of $42,915,000 for the LVD Line Clearing Program, and $10,200,000 for the HVD Line Clearing Program.

Q. Please explain the difference between the 2019 projected Operating and Maintenance ("O&M") spend for LVD clearing and the Case No. U-20134 projected spending for LVD.

A. Approximately $1 million of projected LVD spending was used to meet new regulatory costs for HVD work due to the Michigan Department of Energy, Great Lakes, and Environment's ("EGLE") requirement that the Company and its contractors performing herbicide applications receive coverage under the EGLE's National Pollution and

Discharge Elimination System ("NPDES") General Permit for pesticide applications, as well as additional expense for hazard tree removal along the HVD system. These additional expenses on the HVD system were offset by reducing the expenses projected on the LVD system in Case No. U-20134.

Q. Please explain any deviations between the Company's projected bridge year spending for the LVD Line Clearing Program and the spending level approved by the Commission in the Company's most recent electric rate case order in Case No. U-20134.

A. The Company's projected 2020 bridge year spending for the LVD Line Clearing Program is in line with the spending level approved by the Commission in the January 9, 2019 Order approving the Settlement Agreement in Case No. U-20134. The Company's projected 2020 bridge year spending for LVD is $41.355 million. Together with the projected bridge year spending for HVD ($11.645 million), the Company's total line clearing projected 2020 bridge year spending is $53 million.

Q. Why is the requested spending level for the LVD Line Clearing Program in this filing above the historical average spending in this program?

A. Tree-caused outages on the LVD system and tree-related outages during major weather events have reached unacceptable levels to customers. For the rolling 12-month period ended December 16, 2019, there were 951 customers on 18 LVD circuits that had experienced 12 or more outage incidents. There was a total of 465 outage incidents for these customers of which 285, or 61% of the 465, outage incidents were caused by trees. For the same time period 109,592 customers experienced 5 to 11 outage incidents, 56% of the 14,807 outage incidents experienced by these customers were tree-caused outages.

In addition, conductors downed by trees and tree branches during major weather events pose a significant safety risk to the public and require a large amount of utility resources to secure before service restoration activities begin.

The Company's proposed 2021 test year spending level is the Company's projected attainable spending level based on resource availability towards the goal of attaining an effective seven-year clearing cycle on the LVD system. The current projected outlook for funding a seven-year cycle on LVD and maintaining the four-year cycle on HVD is approximately $120 million per year in line clearing expense.

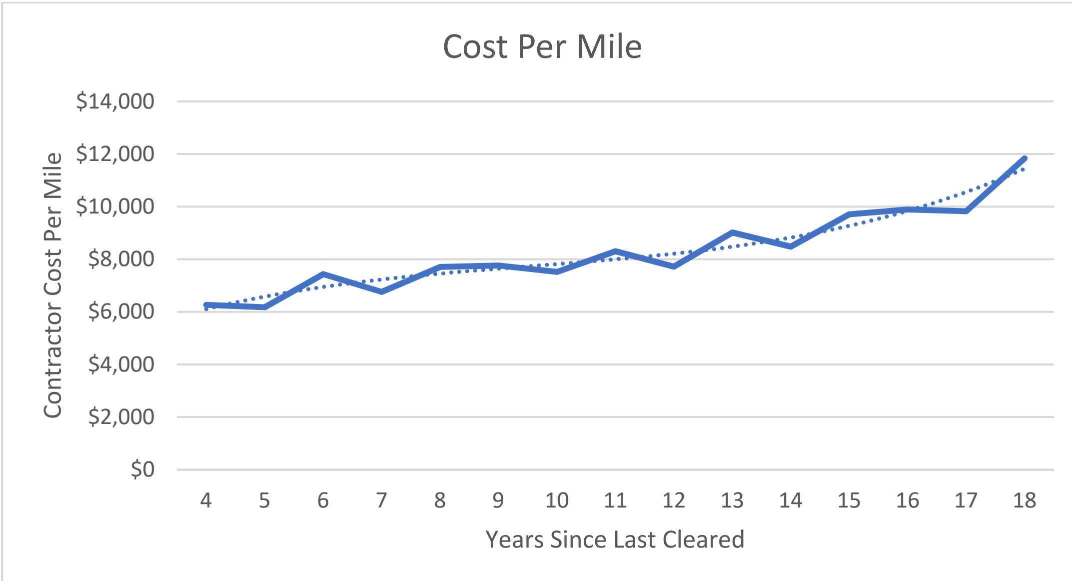
A 2016 benchmarking study from CN Utility Consulting, Inc. ("CNUC") indicates that the industry average clearing cycle is 4.9 years. That 4.9-year industry average clearing cycle results in an industry average of 0.241 tree-related outages per LVD mile per year. For comparison, over the period of 2011 through 2015 (the same period used in the CNUC study) the Company averaged 0.415 tree-related outages per LVD mile per year. Upon analysis, the Company has determined that a seven-year effective cycle would produce substantial reliability benefits. A seven-year effective cycle would result in 0.27 tree-related outages per LVD mile per year, much closer to the industry average presented in the CNUC study.

Q. Does a shorter effective clearing cycle reduce the average cost per line mile to clear circuits?

A. Yes, a longer clearing cycle results in more complex clearing work and requires the removal of more biomass to achieve clearance to conductors. In recent years, the Company has had an effective clearing cycle of approximately 14.2 years. Per a study of the Company's LVD system performed by Environmental Consultants, Inc. in 2014, over

20 feet of a tree's canopy is removed to achieve the needed 10 feet of clearance to conductors at a 14-year clearing cycle and requires the removal of many stems of brush and smaller sized trees growing within the right-of-way. A 7-year effective cycle removes approximately 12 feet of the canopy to achieve 10 feet of clearance and brush removal is less expensive. This equates to a reduction in the cost per mile once the cycle is achieved and circuits are cleared for the first time "on cycle." To be clear, the system needs to be cleared once now in its current state, and again during the subsequent clearing "on cycle." During this subsequent clearing, a reduction in clearing expense is expected. Figure 7 below shows the relationship between clearing costs per mile and the years between clearings. Moving from a 14-year cycle to a 7-year cycle reduces the cost to clear a mile by approximately $1,618 once the system is "on cycle." The Company anticipates that through the test year, and several years thereafter, the additional expense of ramping up crews and inflation will be partially offset with: (i) production increases (maintaining the Company's cost per mile cleared at current levels) on the LVD system; (ii) waste elimination activities (such as process improvements); and (iii) crew retention and skill development.

Figure 7
Clearing Cost per Mile based on Years Since Last Clearing – Contractor Costs



Q. What is the Company's current effective LVD clearing cycle?

A. The Company's current effective cycle is approximately 14.2 years. The Company projects that without a significant increase in funding, line clearing costs per mile will increase resulting in fewer miles cleared, and tree-caused outages will rise across the system increasing service restoration costs.

Q. How does the Company plan to ramp up its LVD line clearing spending in 2021?

A. The increase in spending, miles cleared, and effective cycle length is provided in Figure 8 below:

FIGURE 8
LVD CLEARING RAMP-UP SCHEDULE

Year	O&M Clearing Miles	Capital Clearing Miles	Total Miles	O&M Expense ($Million)	% Cycle	Cycle Years	Clearing Crews
2021	5,223	575	5,798	$71.430	69%	10.1	340
2022	5,986	625	6,611	$81.485	79%	8.9	385
2023	6,346	615	6,961	$86.840	83%	8.4	405
2024	7,654	600	8,254	$104.100	99%	7.1	475
2025	7,914	475	8,389	$106.520	100%	7.0	485

As Figure 8 indicates, in the 2021 test year, the Company will clear 5,798 miles of the LVD system which is 10% of the Company's LVD system miles. This is the equivalent of a 10-year effective clearing cycle and will require approximately 200 additional contractor line clearing full-time equivalent employees above the current crewing level. The Company, in partnership with its large base contractors and expansion of several smaller Michigan-based contractors, expects to meet this required crewing under existing contract terms. These Michigan-based line clearing contractors currently average five crews per company and we are working to expand that employee level to approximately 12 crews per business partner. This will provide approximately 40 additional full-time equivalent employees for line clearing on the LVD system.

The base contractors currently working on the Company's LVD system are preparing for increased crewing for 2021 with increased training and skilling of existing employees throughout 2020. These employees will then be qualified to be crew leaders and will enable the base contractors to increase their full-time equivalent employees by approximately 120 employees. Lastly, two Michigan-based herbicide application vendors have been contracted to provide approximately 40 employees to perform herbicide treatments in compliance with the EGLE's NPDES requirements.

Q. Will requested spending in this case result in the Company being on a seven-year effective clearing cycle in 2025?

A. No, the spending increase requested in this case is the first step of several increases needed to achieve a seven-year cycle and is the amount of increase that the Company can effectively resource and spend in 2021. Additional increases in spending are required in 2022 through 2025 to attain the first year of clearing at the effective seven-year cycle. It will then take several additional years at that spending level to move the whole system to be "on cycle." The spending levels necessary to achieve this seven-year cycle are present in Exhibit A-98 (CAS-1). Support of the multi-year spending plan and support of the seven-year effective cycle is critical to assure the Company's contract business partners that their investment in additional equipment and personnel is a prudent business decision.

Q. What are the historical unit costs for the Company's O&M clearing work in the LVD Line Clearing Program?

A. Historical unit costs are provided in Figure 9 below:

FIGURE 9
LVD LINE CLEARING UNIT COSTS

	2015	***2016***	***2017***	***2018***	***Projected 2019***
O&M line miles cleared	3,633	3,951	3,503	3,218	3,106
O&M Expense ($million)	$31.294	$41.314	$38.360	$39.913	$41.525
$/line mile	$8,614	$10,456	$10,951	$12,403	$13,369

Q. Please explain any variation in unit costs over time.

A. Many variables influence the cost per mile on the LVD system. The four major variables are: (i) cycle length; (ii) labor costs; (iii) fuel costs; and (iv) the allocation of resources to

LVD sub-programs. Three of these variables have caused a significant increase in the cost per mile over the past five years. Longer cycle lengths affect cost per mile as more hours of work are required to clear lines with longer cycles. Secondly, the Company has seen a tightening of the skilled trades labor market in recent years requiring a significant increase in labor expense to retain qualified line clearance tree trimmers on the system. Customers experiencing multiple tree-caused outages within a 12-month timeframe are increasing. This drives LVD expenses to less productive sub-programs (on a cost per mile basis) to alleviate these outages. The repetitive outage sub-program and the new CEMI clearing sub-program average a 70% increase in the cost per mile over full circuit clearing. Lastly, stable fuel costs in the past several years have not resulted in fuel cost increases or decreases to the unit cost.

Q. What benefits will customers experience through the Company completing work, at the requested spending level, in the LVD Line Clearing Program?

A. Increasing the number of miles cleared each year decreases the number of tree-related outages to the system. As shown below in Figures 10 and 11, when a circuit is cleared System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") on that circuit both show an immediate improvement that lasts for several years (year 0 is the year the circuit is cleared).

Figure 10
Projected SAIDI Improvement Post Line Clearing

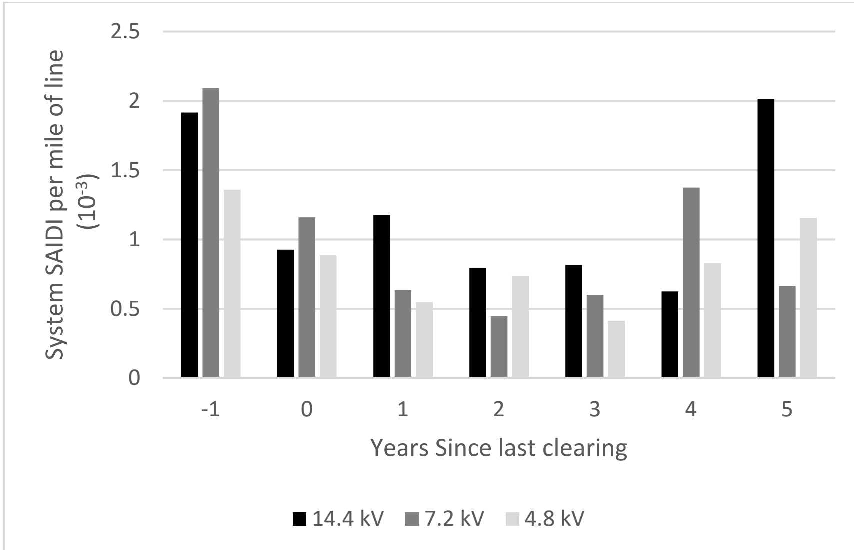
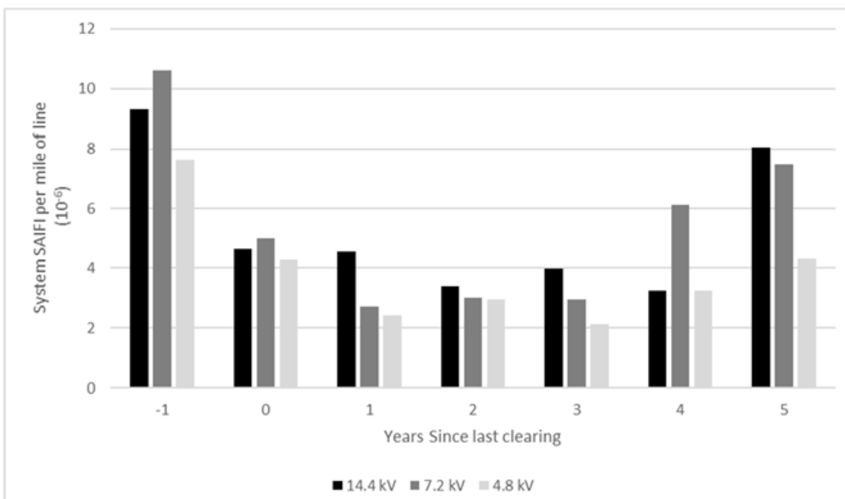


Figure 11
Projected SAIFI Improvement Post Line Clearing



As shown in Exhibit A-99 (CAS-2), a seven-year cycle on LVD would reduce an estimated 2,723 tree-related outage incidents per year by year 2025 and result in a potential reduction in service restoration costs of $2.859 million in 2025. A small potential savings in service restoration costs is expected in the test year and should increase annually to the 2025 amount as more miles are cleared and the number of tree-related outage incidents are reduced. Additionally, Company witness Houtz' direct testimony shows a $3.6 million Interruption Cost Estimate ("ICE") cost in lost revenue to customers for each minute of system SAIDI. Company witness Richard T. Blumenstock's direct testimony covers the reliability benefits of increased forestry spending. Company witness Blumenstock states an estimated reduction in SAIDI from 2020 to 2025 of 28 minutes at proposed reliability spending levels. Of this estimated 28-minute reduction, approximately 26 minutes can be attributed to line clearing at the proposed multi-year funding levels. This 26-minute reduction in SAIDI (which includes reductions to both SAIFI and Customer Average Interruption Duration Index) reduces the ICE community outage losses by $93.6 million in 2025, as described in Company witness Houtz' direct testimony. Therefore, in 2025 with a proposed spending of $120.3 million for line clearing, which is $67.3 million greater than the line clearing O&M expense approved in Case No. U-20134, customers should see a $93.6 million benefit in avoided costs and an O&M reduction in service restoration costs of $2.859 million.

Q. Please list any prioritized projects that make up the requested spending level for full circuit clearing work in the LVD Line Clearing Program.

A. The LVD sub-program for full circuit clearing is not a "fixed" schedule. The list of circuits to be cleared is determined annually based on the most current circuit performance data. During 2020, the Company will identify circuits to prioritize for full circuit clearing for the 2021 test year. Circuits are selected using the Company's forestry reliability model, which provides a ranking of LVD circuits based on projected improvement in reliability, with a goal of maximizing reliability benefit at the lowest cost within each of the Company's service headquarters. Figure 12 below is an example of the forestry model output for the Company's Jackson Service Headquarters for 2020.

Figure 12
Example of the Annual Forestry Model Output

Feeder	Substation	Circuit	Voltage	Circuit Miles	Customer Outages Per Incident	Years Since Last Trim	Trees per Mile	Incidents Per Mile 3 Years Ago	Incidents Per Mile 2 Years Ago	Incidents Per Mile 1 Year Ago	2020 Estimated Incidents per Mile	2020 Estimated Customer Outages Reduced	Circuit Clearing Cost Estimate	Cost per Customer Outage Reduced
78703	WISNER	WISNER	4.8 W	5.7	27	15	60	1.183	0.676	1.183	1.06	114	$37,808	$333
88202	CARY ROAD	LAKE COLUMBIA	14.4 W	33.14	48	14	101	0.152	0.091	0.274	0.49	539	$367,497	$682
42102	LAKE LEANN	LAKE LEANN	14.4 W	64.57	46	14	130	0.422	0.270	0.473	0.64	1,345	$920,392	$684
28802	MICHIGAN CENTER	BALLARD	4.8 W	35.8	44	17	138	0.183	0.183	0.458	0.68	760	$544,757	$717
88203	CARY ROAD	MOSCOW	14.4 W	50.9	42	10	82	0.257	0.138	0.218	0.36	529	$461,801	$873
70402	FERGUSON	BROWNS LAKE	4.8 W	28.21	35	9	117	0.611	0.503	0.431	0.57	398	$363,548	$914
88502	BURTCH ROAD	WELCH LAKE	14.4 W	31.98	56	12	161	0.438	0.110	0.247	0.48	606	$566,223	$934
60903	NAPOLEON	NORVELL	4.8 W	33.69	50	11	140	0.180	0.330	0.150	0.47	552	$520,264	$943
16502	LESLIE INDUSTRIAL	INDUSTRIAL	4.8 W	37.57	16		107	0.307	0.000	0.153	1.10	462	$443,997	$961
63902	PARNALL	PARNALL ROAD	4.8 W	36.88	56	8	132	0.343	0.228	0.257	0.36	516	$536,021	$1,040
29502	STOCKBRIDGE	STOCKBRIDGE	4.8 W	7.44	19	20	95	0.263	0.132	0.263	0.74	74	$78,041	$1,055
129402	BROUGHWELL	ONONDAGA	14.4 W	46.83	74	5	99	0.174	0.152	0.174	0.16	385	$507,720	$1,318
129602	BLACKMAN	HURST	14.4 W	39.8	36	10	164	0.588	0.134	0.535	0.49	489	$719,816	$1,471
67401	DEXTER TRAIL	MILNER	4.8 W	18.47	39	13	213	0.057	0.287	0.401	0.57	290	$432,210	$1,488
42101	LAKE LEANN	BUNDY HILL	14.4 W	62.72	31	12	153	0.281	0.281	0.169	0.51	689	$1,055,578	$1,531
1902	ROBERTS STREET	DETTMAN	4.8 W	11.61	19	19	131	0.337	0.000	0.421	0.70	108	$166,741	$1,538
112802	GREGORY	UNADILLA	4.8 W	49.59	41	8	186	0.443	0.317	0.359	0.45	639	$1,014,390	$1,587
41902	CONCORD	KING ROAD	4.8 W	43.07	36	10	149	0.188	0.188	0.305	0.40	443	$703,922	$1,588
29501	STOCKBRIDGE	MORTON	4.8 W	80.92	34	9	95	0.107	0.094	0.175	0.27	520	$848,802	$1,633
1904	ROBERTS STREET	FOOTE HOSPITAL	4.8 W	2.78	11		131	0.292	0.000	0.292	1.13	24	$39,926	$1,641
25903	HANOVER	HANOVER	4.8 W	41.44	26	8	133	0.350	0.457	0.215	0.44	331	$606,867	$1,832
21802	WILDWOOD	MACKLIN	4.8 W	8.84	24	16	244	0.880	0.352	0.440	0.87	130	$237,266	$1,832
73502	LESLIE	HULL ROAD	4.8 W	24.81	19	15	130	0.301	0.172	0.129	0.57	190	$354,639	$1,862
75902	REYNOLDS	SEARS	14.4 W	37.9	34	8	201	0.433	0.251	0.342	0.42	376	$838,713	$2,228
137202	BALZER	COMSTOCK	14.4 W	43.11	49	4	122	0.373	0.186	0.117	0.17	248	$577,255	$2,325
25901	HANOVER	PULASKI	4.8 W	35.55	21	13	204	0.450	0.330	0.240	0.63	325	$798,720	$2,456
39401	GRASS LAKE	GRASS LAKE	4.8 W	58.48	21	9	80	0.037	0.056	0.112	0.23	196	$512,128	$2,611
41901	CONCORD	SWAINS LAKE	4.8 W	43.29	27	9	176	0.215	0.241	0.241	0.39	316	$835,872	$2,648
77202	SCIPIO	POPE ROAD	4.8 W	65.44	21	9	130	0.122	0.227	0.140	0.34	326	$932,651	$2,861
37603	BATTEESE	MUNITH	14.4 W	82.45	33	5	131	0.318	0.118	0.236	0.19	359	$1,187,972	$3,310

Q. Has the Company reviewed the effectiveness of its Forestry Department and Line Clearing Program?

A. Yes, in 2018, the Company employed KPMG International as an independent auditor to review the Forestry Department. The scope was designed to assess and evaluate the following areas: (i) forestry governance, processes, procedures, policies, and controls; (ii) roles, responsibilities, resources, and organization maturity; and (iii) planning, work management, and monitoring activities. The independent auditor identified multiple positive highlights including: (i) a strong forestry leadership team with substantial knowledge and experience in technical and field operations and a demonstrated desire to deliver solid forestry performance; (ii) a forestry management planning process that includes refined modeling and data analytics, which represents better industry practice and planning maturity ahead of industry peers; (iii) detailed and timely measuring and reporting of third-party forestry management contractor performance, including a strong quarterly contractor performance scoring process, which includes areas such as safety performance and on-call/storm and customer relations responsiveness; and (iv) strong use of data visualization and strong participation in the reliability rally room.

Q. Does the Company request to recover the entirety of its LVD line clearing O&M spending in the 2021 test year through base rates?

A. Yes, it does.

<u>HVD LINE CLEARING</u>

Q. Please explain what projects, activities, and other types of work will be funded by spending in the HVD Line Clearing Program.

A. Similar to the Company's LVD Line Clearing Program, the Company's HVD Line Clearing Program consists of an IVM program that promotes reliability by reducing tree-caused outages and decreases the impact of storms. The HVD Line Clearing Program consists of four categories of work: (i) maintenance tree clearing; (ii) brushing and herbicide treatment; (iii) demand clearing; and (iv) noxious weed control (grass and weed mowing to meet local ordinances).

Q. What is entailed in maintenance tree clearing?

A. The Company's HVD maintenance tree clearing work consists of scheduled four-year 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 and/or structurally weakened.

Q. What is needed in 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 is: (i) 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 involved in demand clearing?

A. The Company's demand clearing work addresses emergent vegetation threats to the HVD system. These threats are identified by HVD vegetation inspections and by helicopter patrols of the HVD system. Hot-spotting work most often involves partially uprooted trees that are leaning towards the line that will eventually fall onto the line. These situations require immediate remediation to prevent an imminent outage.

Q. What is required in noxious weed control?

A. The Company's noxious weed control work maintains compliance with local ordinances for maintaining vegetation on fee-owned HVD rights-of-way in predominantly urban areas. These ordinances do not permit vegetation growth above a specified height, requiring three to six mowing cycles of affected rights-of-way each year, with variation due to rainfall and temperature.

Q. What is the Company's projected 2021 test year spending level, for which it is requesting cost recovery, in the HVD Line Clearing Program?

A. The Company is projecting HVD line clearing expenses of $12,570,000 in the 2021 test year, as shown in Figure 13 below and in Exhibit A-98 (CAS-1).

Q. How would these projected expenses be allocated among the categories of work described above?

A. The Company is projecting expenses in the test year for each category as identified in Figure 13 below:

FIGURE 13
HVD LINE CLEARING EXPENSES

Categories	Expenses
Full circuit clearing	$6,925,000
Brush control	$4,710,000
Hot-spotting	$75,000
Noxious weed control	$40,000
Line Clearing Admin	$820,000
Total	**$12,570,000**

Q. What has been the historical actual spending in the HVD Line Clearing Program for the past five calendar years, including the five-year average?

A. The Company's historical actual spending in the HVD Line Clearing Program for the past five calendar years is shown in Figure14 below:

FIGURE 14
HVD LINE CLEARING UNIT COSTS

	2015	*2016*	*2017*	*2018*	*Projected 2019*
Line miles cleared	734	1,093	1,019	1,081	1,064
O&M Expense ($million)	$5.718	$9.468	$11.394	$12.036	$11.475
$/line mile	$7,795	$8,662	$11,182	$11,134	$10,785
Effective Cycle (years)	6.4	4.3	4.6	4.4	4.4

The five-year average of this actual spending is $10,018,200.

Q. If spending in any of the five historical years is a significant outlier, please explain why this happened.

A. The five historical years reflect the Company rapidly expanding its spending on hazard tree removal after 2015, due to Emerald Ash Borer ("EAB") activity. EAB is a non-native invasive pest; its larvae feed on native ash trees resulting in near 100% mortality. This effort was substantially completed in 2018, but the subsequent reduction in hazard tree expenses has been partially offset by an increase in pay rates for line clearing crews.

Q. What spending level for the HVD Line Clearing Program was approved in the Company's last electric rate case order?

A. The Commission approved a settlement agreement among the parties in Case No. U-20134. As part of that settlement agreement, the parties agreed to a $53 million Line Clearing Program spending commitment by the Company for calendar year 2019. This amount was in line with the Company's filed line clearing spending level in that case, which consisted of $42,915,000 for the LVD Line Clearing Program, and $10,200,000 for the HVD Line Clearing Program.

Q. Please explain any deviations between the Company's projected bridge year spending for the HVD Line Clearing Program and the spending level approved by the Commission in the Company's most recent electric rate case order.

A. The Company's projected 2020 bridge year spending for the HVD Line Clearing Program is in line with the spending level approved by the Commission in the January 9, 2019 Order approving the Settlement Agreement in Case No. U-20134.

Q. Why is the requested spending level for the HVD Line Clearing Program in this filing above the historical average spending in this program?

A. As noted above, the Company increased its spending in the HVD Line Clearing Program to address EAB activity. This resulted in an upward spending trend beginning in 2016, effectively raising the current spending level above the historical average that still includes the lower pre-EAB year of 2015. Although the affected ash trees are now largely addressed, the subsequent reduction in hazard tree expenses has been partially offset by an increase in pay rates for line clearing crews. As discussed earlier in my direct testimony, the additional increase in pay rates for line clearing crews resulted in higher retention rates and a more skilled work force. Additionally, a larger portion of the HVD line clearing expense is treatment of brush utilizing herbicide applications. Approximately $1 million of spending was used to meet new regulatory costs for HVD work due to the EGLE's requirement that the Company and its contractors performing herbicide applications receive coverage under the EGLE's NPDES General Permit for pesticide applications. The Company's HVD Line Clearing Program, particularly the full circuit clearing work, is already on the target four-year cycle. The Company expects to continue spending roughly the same amount on the HVD Line Clearing Program going forward to maintain this cycle.

Q. What are the historical unit costs for the Company's clearing work in the HVD Line Clearing Program?

A. Historical unit costs are provided in Exhibit A-98 (CAS-1).

Q. Please explain any variation in unit costs over time.

A. Several factors drove unit costs higher since 2015 including: (i) EAB and pine bark beetle mortality to trees; (ii) increased expense to meet new regulatory requirements for herbicide applications; and (iii) increase in pay rates for line clearing crews to retain a Michigan-based work force. In 2019, the Company saw a leveling off from these unit cost increases as retention of the work force resulted in greater productivity and work method adaptations to the new regulations taking effect.

Q. What benefits will customers realize through the requested spending level in the HVD Line Clearing Program?

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 2015 through 2019, the average customer impact of an LVD line tree outage was 45 customers and the average customer impact of HVD line outage was 670 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. 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. Please list any prioritized projects that make up the requested spending level for full circuit clearing work in the HVD Line Clearing Program.

A. In 2021, the Company is planning HVD line clearing on the lines listed in Exhibit A-100 (CAS-3).

Q. What has been the Company's recent historical performance with respect to completing its projected levels of HVD line clearing?

A. In 2017, the Company's target was to clear 1,016 miles of HVD lines, and the Company met that target by clearing 1,019 miles. In 2018, the Company's target was to clear 1,150 miles of HVD lines, and the Company cleared 1,081 miles. In 2019, the Company's target was to clear 1,064 miles of HVD lines, and the Company is projecting to meet this target.

<u>PROPOSED PLAN RESOURCING</u>

Q. Does Consumers Energy have the personnel and other resources to complete all of its projected LVD line clearing work if the Commission approves the requested spending level?

A. The Company, through its Forestry Department and its line clearing contractors, has been resource planning for the LVD system ramp-up. Contractors are training and skilling approximately 60 tree trimmers currently working on the system to become crew leaders. This will enable the hiring of an additional 120 employees during the test year to be paired with a skilled crew leader. The Company established new contracts with two contractors to perform herbicide application work (meeting the new EGLE requirements) totaling approximately 40 additional full-time equivalent employees. The Company's base line clearing contractors are securing additional specialized line clearing equipment including: (i) brush mowers; (ii) mechanical side trimmers; (iii) backyard aerial lifts; and (iv) remote-controlled mechanical trimmers. Other specialized equipment, including clearing by helicopter-borne saws (such as rotoblade) and Altec's Heartland grapple/trimmer, is under review for appropriate work. The remote-controlled mechanical trimmer and Heartland grapple/trimmer (also remote-controlled) provide opportunities to individuals that do not meet the physical requirements of traditional line clearance tree trimmers and provide employment opportunity to more individuals.

A great issue for resource planning is certainty of funding. Aerial lift trucks, chippers, and specialized equipment must be ordered well in advance of delivery dates (typically 6 to 12-month lead times). Supporting a multi-year plan to attain a seven-year effective cycle on LVD helps to assure these contractors that the capital investment they make in equipment can be recovered over time through use on the Company's system. This issue is critically important to the smaller Michigan-based businesses that the Company is encouraging to grow for resource needs of the system. These smaller companies cannot tolerate the risk involved with large equipment purchases without assurance of cost recovery through longer-term contracts.

For in-house staffing, the Company continues to recruit forestry graduates from Michigan Technological University and Michigan State University, as well as graduates from several other universities that offer degrees in natural resource management.

Q. Does the Company have the personnel and other resources to complete all of its projected HVD line clearing work if the Commission approves the requested spending level?

A. Yes, the Company currently has the resources in place to maintain the HVD system on a four-year clearing cycle.

Q. Does this conclude your direct testimony in this case?

A. Yes, this concludes my direct testimony.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697

DIRECT TESTIMONY

OF

R. MICHAEL STUART

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

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

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Metrics and Strategic Planning.

Q. Please review your educational and business experience.

A. I graduated from Michigan State University in December of 1985 with a Bachelor of Arts degree in Business Administration. Since joining Consumers Energy in June of 2000, I have held various positions in the Supply Chain, Electric Meter Operations, Business Technology Support, Strategy Mobilization and Integration, and Quality Lean Office Departments.

Q. What are your responsibilities as Director of Metrics and Strategic Planning?

A. In the Director of Metrics and Strategic Planning role, I am responsible for the development, governance, and administration of the operational metrics incorporated in the Company's Employee Incentive Compensation Plan ("EICP").

Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes, I filed testimony in Case No. U-17643 and testified in Case Nos. U-17735, U-17882, U-17990, U-18124, U-18332, and U-20650.

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

A. The purpose of my direct testimony is to provide support for Consumers Energy's request for rate recovery for the test year EICP employee compensation costs. Specifically, I will discuss Consumers Energy's EICP operational performance goals and how the EICP goals provide customer-related benefits.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-103 (RMS-1) EICP Performance Measures

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

Q. Please explain the process for designing the Company's EICP goals.

A. Each year, the Company identifies key operational and financial goals to focus on for the next year. A list of these goals is provided in Exhibit A-103 (RMS-1). The EICP operational goals are key goals that focus on continuously evaluating work and delivery processes for opportunities to improve (e.g., waste elimination, first time quality, etc.) and enhance productivity and customer value, and fulfill our purpose to provide world class performance delivering home-town service.

Q. Is there a direct tie between the design of the current operational incentive plan and desirable benefits for customers?

A. Yes. There is a direct tie between the current design of the operational incentive plans and desirable benefits for customers. The operational incentive plan focuses on safety, reliability, productivity, and customer value, which are all desirable benefits for customers. The Commission should permit recovery of these costs in the current case.

Q. Will the structure of the EICP goals for 2020 be similar to 2019?

A. The specific performance measures and targets for 2020 have not been finalized yet. However, as in prior years, the performance measures will be a combination of measures related to operational performance and financial health. I anticipate that, as for

2019, for non-officers the operational performance and financial health goals will be weighted equally. I anticipate that for officers the attainment of the financial measures will again be a threshold component with the operational goals as a modifier.

Q. Do you believe that benefits to customers from the EICPs will, at a minimum, be commensurate with the programs' costs?

A. Yes. Company witness Amy M. Conrad and I present evidence in support of including EICP costs at the 100% payout level showing that including these costs will not result in excessive rates and that the costs of the EICP will, at a minimum, be commensurate with the programs' costs. Company witness Conrad discusses various benefits to customers from the design of the Company's EICP. In addition, there are quantitative benefits. The design of the EICP clearly leads to lower costs and improved service which benefit our customers.

Q. Has the Company quantified customer benefits that are tied to its EICP?

A. Yes. Although specific quantification of the costs of the program and the benefits is not easy to perform for every metric included in the program, the Company has evaluated direct quantitative benefits of two key metrics of the program and has assessed indirect and/or qualitative benefits associated with the other metrics.

Q. What are the results of the direct quantitative benefits evaluations?

A. The benefits associated with just these two metrics confirm the Company's conclusion that there are substantial benefits that accrue to the customer. The first of those metrics is employee safety. Employee safety incidents decreased by 79% from 2006 through 2018. The resulting reduction in lost work days and medical expenses approximates $4.4 million of annual direct savings, and $7.4 million of annual total savings that accrue to the benefit of the customer. The second metric that can be translated to cost avoidance for our customers is in the area of distribution reliability. Using cost per outage minute estimates from Berkeley Labs[1], the 5.7 minute annual average reduction in outage minutes from 2006 to 2018 results in annual economic benefits to our customers in excess of $17 million.

Q. What are the results of the indirect and/or qualitative benefits assessments?

A. Each of the other metrics provides significant value to the customer. First, the Customer Experience Index goal focuses on ensuring that when customers contact Consumers Energy, customer needs are met, the interaction is easy for the customer, and the experience is enjoyable for the customer. This results in enhanced productivity (e.g., reduces 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). Second, the Customer On-Time Delivery goals emphasize completing customer-requested work according to the customers' timeline (typically a shorter, quicker lead time) and within a narrower span of time. In order to deliver on those goals, first time quality in customer interactions, design, scheduling, and field work is required, resulting in enhanced productivity and reduced costs. Additionally, meeting customer timeline commitments within a narrower, often shorter, window minimizes the impact on our customers' schedules, enhances economic development (which can lead to better customer rates by spreading fixed costs), and produces customer satisfaction and value. Third, the electric Generation Customer Value goal focuses on optimizing the use of the Company's electric generation fleet to maximize customer value.

[1] https://www.osti.gov/servlets/purl/963320

Next are two goals that are generally associated with gas operations: (i) Eliminate Vintage Services; and (ii) Gas Flow Deliverability. Both deliver customer benefits by improving safety for combination (electric and gas) and gas only customers and reducing the Company risk profile, which yields more favorable Company credit ratings and financing terms (ultimately reducing customer rates). Finally, are the benefits resulting from our Company focus on our Cyber Safety goal related to minimizing phishing email click rates. There are a multitude of reasons to focus on phishing click rates. First, according to the 2016 Enterprise Phishing Susceptibility and Resiliency Report,[2] 91% of cyber-attacks and the resulting data breach begin with a phishing email, phishing campaigns are up 55%, ransomware attacks are up 400%, and Business Email Compromise losses are up 1,300%. Second, the Company sees phishing attacks daily, and in 2017 many utilities including Consumers Energy were targeted by nation state attackers attempting to gain access to electric grid infrastructure. Additionally, potential costs for a cyber-attack against the Company are significant. According to the Lansing State Journal, the 2016 Lansing Board of Water and Light ransomware attack was initiated via a phishing email and cost them $2.4 million in operating costs.[3] The Company estimates through our enterprise risk mapping process that a sizeable data breach from phishing would likely result in costs in the range of $10 million after insurance coverage.

Q. Has there been an attempt to quantify these indirect and/or qualitative benefits?

A. Yes. To quantify the benefit to customers of productivity and customer value metrics such as these, we can look at the Company's actual Operating and Maintenance ("O&M") costs versus what they would have been had they instead grown at the United States Consumer

[2] https://cofense.com/enterprise-phishing-susceptibility-report/
[3] https://www.lansingstatejournal.com/story/news/local/2016/11/25/bwl-prepared-ransomware-attack/94332454/

Price Index ("CPI") inflation rate. Since the deliberate focus on productivity and customer value EICP metrics against the 2006 performance baseline, the Company's O&M costs have remained practically flat on average, while the United States CPI inflation rate grew by an average of 1.9% per year. The average annual savings during this time period is $242 million, which benefits customers.

Q. Why have you included both electric and gas benefits in your quantification?

A. Consumers Energy's utility operations are combined in one organization. Establishing operational goals in the critical areas of safety, reliability, productivity, and customer value helps keep employees focused on the importance of safety, reliability, productivity, and customer value for both the electric and gas operations. The quantified benefits show that benefits to electric customers clearly exceed the electric incentive compensation amounts that Consumers Energy has requested to be included in rates in this case. The EICP metrics are based on annual targets that support the achievement of Consumers Energy's continuous improvement goals that significantly benefit the customers.

Q. What portion of the indirect and/or qualitative benefits that you have quantified above do you conclude benefit electric customers?

A. A portion of the quantified benefits in the areas of employee safety, productivity, and customer value benefit electric customers. Utilizing an allocation of 66% for electric customers, this equates to annual savings for gas customers of $182 million, far exceeding the total costs of the EICP allocated to electric customers.

Q. Why did you use a 66% allocation to evaluate benefits to electric customers?

A. The 66% allocation is based on the total number of electric employees as a percentage of total number of Consumers Energy employees. Using the percentage of total employees is a reasonable allocation methodology to use to allocate the employee safety, productivity, and customer value benefits identified above.

Q. Should the Company be pursuing these benefits independent of the EICP?

A. Yes. The EICP takes this into consideration. As discussed by Ms. Conrad in her direct testimony, incentive mechanisms help communicate priorities, engage employees in business success, reward valued skills and behaviors, and create business understanding for employees. The EICP is structured in a way that helps to highlight certain important elements of utility service and to emphasize to employees that they should pay attention to achieving these targets. Making it clear to employees that a portion of their total compensation depends upon their collective ability to meet these targets, communicates clearly to employees the importance of serving customers and encourages them to deliver their best performance. Because the EICP has been designed so that the incentive payments simply bring employee compensation to a competitive market-rate level, I think a better way to describe this program is that employees are penalized if the targets are not achieved.

Q. Do you believe that the EICP is the reason that the above benefits have been realized?

A. I believe that the design of the EICP is intended to, and does, make it significantly more likely that these customer benefits will be achieved. By placing a portion of employees' market-based compensation at-risk, they are incentivized to deliver on the EICP goals related to safety, reliability, productivity, and customer value.

Q. Do you believe that any of the metrics included in the EICP are duplicative?

A. No. The metrics have been selected to create a designed, balanced focus on safety, reliability, productivity, and customer value that results in broad customer benefits.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

JEFFREY D. TOLONEN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Jeffrey D. Tolonen, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I have been employed at Consumers Energy for over 18 years. The first 13 years were spent in the Information Technology ("IT") Department as an application developer, systems analyst, and solution architect. During this time, I implemented IT projects and enhancements in the Customer Financials area including payments, collections, and assistance programs. I moved into the Smart Meter Implementation Program in 2010 where, as solution architect, I contributed to the architecture and IT systems delivery through several phases of the program. I then spent two years starting in 2014 in the Electric Distribution Engineering area within the Grid Modernization group as a grid systems architect. In this role I was responsible for delivering the smart meter and electric distribution data historian software, as well as working on the IT systems roadmap needed to support modernization of the electric distribution system. I returned to the IT Department in 2016 as Application Development team leader, and I am currently the manager of the Application Development Team. In this capacity, I have responsibility for providing application development resources to support the IT portfolio teams, which include Customer Experience and Operations; Corporate Services and Governance; Transformation, Engineering and Operations Support; and the IT Operations area.

Q. Would you please state your educational background?

A. I earned a Bachelor of Science degree from Western Michigan University in May of 1996 with a major in Aeronautical Engineering and a corresponding minor in Mathematics.

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

A. No.

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

A. The biggest challenge the IT department currently faces is the ability to operate its systems and networks within the given five-year average Operations and Maintenance ("O&M") budget constraint of previous rate cases. As documented in detail later in this testimony, the use of a five-year average to project the Company's IT Operations O&M expenses puts the Company and service to its customers at risk. The projected cost to support the technology asset base and increased use of cloud computing is significantly greater than the historical five-year average for IT Operations O&M expenditure. To appropriately support the assets and keep them secure, the Company needs approval for the projected IT Operations O&M expense as requested in this testimony. Approval based on a five-year average will not sufficiently support and maintain the capital expenditures made previously on behalf of the Company's customers.

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

A. The purpose of mydirect testimony is to describe the IT and Security Departments' ("Security") O&Mexpenses and capital expenditures needed to maintain existing IT and security systems and enable new programs and services for our customers. This testimony will also describe how the increasing use of technology correlates to an increase in the requested recovery and how the Company's digital investments can meet needs of its customers in this environment. In addition, this testimony will demonstrate why it is so important to achieve full recovery on the requested expenses and expenditures and the resulting positive impact to the Company's customers.

The technology landscape at Consumers Energy has grown and changed significantly over the last five years, and that change continues to accelerate with each new year. The pace of technology change is increasing, cyber security threats have intensified, and the Company's dependence on technology to provide safe, reliable, and affordable electricity with high levels of customer satisfaction has increased. The need for new digital capabilities to offer new services to customers, improve the customer experience, improve system safety, reliability, and functionality, while complying with regulatory requirements, makes the Company's technology investments prudent and in the best interests of its customers, who desire safe, reliable, and affordable electricity. These drivers increase the complexity of the Company's technology landscapes and consequently increase the operating expense needed to maintain and operate them securely and reliably. The importance of this maintenance is reflected in the Company's significantly higher O&M spend to operate its systems as compared to the prior allotted five-year average of operational O&M.

The Company is asking for recovery of costs incurred to maintain safe, reliable technology assets, just like it maintains safe, reliable electric assets. The Company is also asking for financial support for new technical capabilities needed to realize the ambitions of the Company's Integrated Resource Plan ("IRP") and Electric Distribution Infrastructure Investment Plan ("EDIIP"). And, the Company is asking for recovery of costs planned to enable residential and business customer programs that enhance customer experience and change with customer needs and behaviors. Without these new digital capabilities, the Company will be unable to achieve the key strategic outcomes of these plans, including: (1) physical and cyber safety improvements for our customers and employees; (2) the ability to provide customers with the data, technology, and tools needed to manage their energy consumption; (3) improvements in reliability and resiliency via physical and system hardening; and (4) investments to proactively manage the electric system.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

Exhibit A-104 (JDT-1)		Summary of Actual and Projected Information Technology Operations O&M Expense for the Years 2018, 2019, 2020, and Test Year 12 Months Ending December 31, 2021;
Exhibit A-105 (JDT-2)		Summary of Actual and Projected Information Technology Investments O&M Expense for the Years 2018, 2019, 2020, and Test Year 12 Months Ending December 31, 2021;
Exhibit A-12 (JDT-3)	Schedule B-5.3	Projected Capital Expenditures Information Technology Summary of Actual and Projected Electric and Common Capital Expenditures;
Exhibit A-106 (JDT-4)		Synopses Containing Descriptions, Scope, Benefits, Implementation Dates, and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures For the Years 2018, 2019, 2020, and2021.
Exhibit A-107 (JDT-5)		Historical and Projected 13-Month Average of IT Cloud Computing Prepaid Balance

Exhibit A-108 (JDT-6)	Projected Information Technology Highest Cost Top 25 Projects Project Descriptions, Functionality, Alternatives, Timelines, Spending Plans, Benefits, Cost/Benefit Ratio, For the Projected Test Year 12 Months Ending December 31, 2021.

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

A. Yes.

<u>DESCRIPTION OF THE IT DEPARTMENT</u>

Q. Please describe the purpose of the IT Department.

A. The purpose of the IT Department is to provide and maintain reliable and secure IT solutions and services that support the delivery of excellent customer experiences and other business objectives, including execution of the Company's EDIIP. The Company has adopted a digital strategy to guide its approach for technology investments and operations. Digital, as the Company describes it, is connecting people, "smart" things, and information (data) to create better products, services, and ways of working. The Company's evolving and pragmatic digital strategy will support:

- Adaptable delivery practices (e.g. adopting Agile frameworks);
- Widespread building and use of digital skills and practices;
- A move to cloud solutions where and when appropriate;
- Treating data as an asset and deployment of analytics on a larger scale;
- Deployment of a consistent asset management system and framework;
- Deployment of integrated control systems for system automation;
- Continuous operational improvements via automation; and
- A commitment to ensure digital investments do not introduce unnecessary risk to the Company or its customers and to protect sensitive data and critical infrastructure from cyber and physical threats.

Q. Please describe the functions that the IT and Security Departments perform.

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

Security ensures that Company systems, data, employees, and customers are protected from various cyber and physical threats facing the Company. Security also ensures regulatory compliance with a multitude of state and federal regulations, and manages security risk, awareness, and data privacy. There are strong interdependencies between the functions performed by the IT and Security teams. IT is responsible in many cases for implementing technology security best practices deemed necessary by the standards and practices determined by Security.

Q. Please describe the Company's computing infrastructure.

A. Consumers Energy's computing infrastructure consists of hardware and communications networks utilized by virtually all aspects of the Company's operations. Hardware includes servers and data storage devices, workstations, printers, collaboration technologies, and mobile devices. Communications networks for telephone and radio systems enable voice, data, and wireless communications across the Company. The Company also employs both public and private cloud platforms to automate the deployment of virtualized computing infrastructure on top of the previously mentioned hardware and networks to increase the speed and quality of infrastructure deployment.

Q. How does technology support the Company's electric strategy specifically?

A. Technology is an integral part of all aspects of the Company's electric strategy from generation all the way to the customer. The Company's IRP, filed in Case No. U-20165, which established the Company's long-term Clean Energy Plan, provides the direction. To realize this plan, the Company needs to invest in new technology as the future of energy generation is increasingly more distributed and complex. As the Company increases investment in demand response, energy efficiency, and grid modernization tools, these virtual "power plants" will help the Company reduce energy demand and manage customer load efficiently and effectively. This will be accomplished by incenting customer behavior to save energy while reducing customer costs using energy efficient devices and processes. The addition of solar energy sources, wind energy sources, and battery storage to the generation landscape will also require the utilization of technology systems to operate and manage them safely and efficiently.

The Company's EDIIP is driven by the following core objectives and principles as it continues to move to a clean energy future: (1) safety and security; (2) reliability; (3) system cost; (4) sustainability; and (5) control. A key area of this plan includes building for the future through the use of new technologies to support the electric devices, communications, and analytics for capabilities like Volt-VAR Optimization and Conservation Voltage Reduction that support energy efficiency and peak demand reduction as described in Company witness Richard T. Blumenstock's testimony. The plan also relies on technology to enhance electric reliability and resilience through Fault Location, Isolation, and Service Restoration ("FLISR"), as well as enabling initiatives for customer- or Company-owned Distributed Energy Resources, like solar and wind generation, and energy storage systems.

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

Q. How do the Company's customers benefit from the technology and services provided by the IT Department now and in the future as described in the EDIIP?

A. The Company's customers benefit from the technology provided by IT both directly and indirectly, as highlighted by the following scenarios a customer might encounter.

In the first scenario, a large storm system with high winds and lightning causes a number of downed electric lines, resulting in customer outages. When that happens, the Distribution Supervisory Control and Data Acquisition ("DSCADA") system immediately alerts the electric system control center. This is possible because the electric fault caused by the wire down is identified immediately by a device in the substation communicating in real time (every 4 seconds) back to the DSCADA system. Before DSCADA, customers needed to call the Company and system control would dispatch a substation engineer to confirm the circuit device fault. In contrast, today's DSCADA and communications technology in the substation eliminate the time needed to confirm an outage occurred. Once the Automated Distribution Management System ("ADMS") is implemented, this

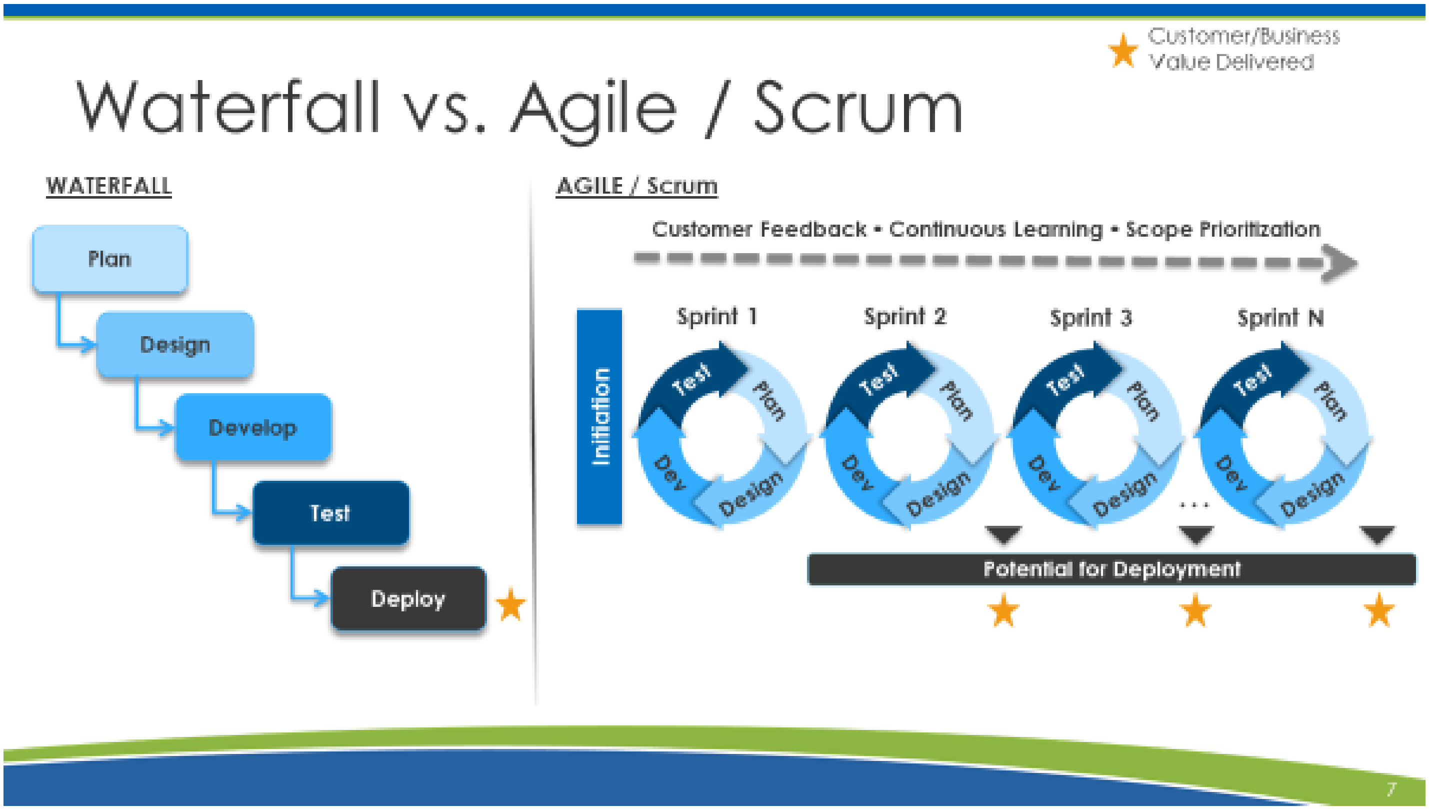
DSCADA data will get picked up by ADMS and confirm through communications technology that the Automated Transfer Reclosers ("ATR") detected a fault on a circuit. The ATR segregates the damaged section of the circuit, automatically reroutes the electric load, and restores power to some of the customers on that circuit. The ADMS system will also calculate the location of the fault by consolidating information provided by intelligent communicating field devices, including distribution line sensors, using the FLISR capability. Once the location of the fault is known, crews are immediately dispatched to the location to begin restoration service work. Meanwhile, the storm restoration support teams are mobilized in accordance with the Company's Incident Command System ("ICS") and begin monitoring and managing restoration crews, wire downs, equipment, and materials logistics through the Company's internal software—Catastrophic Crewing and the Storm Dashboard. These software applications ensure the right people have the right tools and materials so that restoration activities happen as safely, quickly, and efficiently as possible. From the first outage, the smart meters are reporting in to the Outage Management System ("OMS") within ADMS. The customers are beginning to experience and report power outages through the outage center online, using their mobile phones, calling in to the Interactive Voice Response system, or speaking to a live agent. All communication sources are integrated technology systems ensuring a seamless and efficient communication platform for our customers and the Company. The customer checks timely outage information on the outage map and can sign up to receive text message updates with the most current Estimated Time to Restore for their home or business. Customers can then make informed decisions or necessary arrangements to get through the storm outage.

In another scenario, a customer wants to understand how they can save money and simultaneously be more environmentally conscious. The customer previously signed up to receive emails and text messages from the Company for outage information and billing reminders, taking a mental note during the last storm to check out the website. They navigate to ConsumersEnergy.com, where they immediately find information about the newest energy efficient solutions for their home, energy assessments, energy saving tips, and links to learn more about programs to save energy and money. They decide to explore the new demand response program they heard about from their neighbor, who was saving energy and money during the peak summer months without noticing the inconsequential temperature changes in their home during the high usage peak events. Behind the scenes, technology is used to control the customer's air conditioning unit and report back to the peak cycling vendor and the Company. More technology is used to combine this device cycling data with data from the customer's smart meter to create an accurate bill reflecting the cost savings for the customer. At the same time, technology supports the analyses of the customer's usage patterns to provide powerful insights that determine the best money and energy saving program for the customer. Technology is also used to continually improve the effectiveness of these types of programs. The customer uses technology to view their energy usage data on a web page to see how much they are saving and guide their future energy choices.

Q. How is the IT Department contributing to increased speed, frequency, and quality of digital investments, thereby increasing value to customers and internal business units?

A. The IT Department continues to expand the adoption of Agile practices for delivering technology solutions due to the numerous benefits it provides. Agile focuses on iterative planning and development and incremental delivery, which enables teams to deliver customer value earlier and more frequently, in contrast to a traditional waterfall delivery approach. This is illustrated in the diagram below. A key component is the continual refinement and prioritization of scope based on the value it provides. By iteratively planning and developing small blocks of the prioritized scope, the Company can ensure teams are continually delivering the highest value items first, while reducing or avoiding investment on the low-value or "nice-to-have" items. Each iteration provides the opportunity to respond to changes or unknowns, reducing the risk and potential for significant, costly changes that are more likely exposed late in the building or testing phases of a traditional waterfall project.

As an example, an Agile team was assembled in 2019 to improve the Company's Service On-time Commitment to our customers through technology enhancements. The team was made up of blended roles that crossed business and IT architects, analysts, developers, and testers. Collectively, they successfully executed a major work center transformation through customer application and SAP work management system changes. This increased the volume of service work that is able to be offered to customers within three-hour appointment windows from 53% to 88%, while supporting our high customer service goals of meeting those customer commitments and expectations increased from 85% to 98% from April 2019 to August 2019.



Q. Why is the Company moving to cloud solutions vs. on-premise solutions?

A. Cloud computing offers several benefits over on-premise computing solutions under certain conditions. Some notable benefits include increased speed of delivery, scalability, regular automatic updates, and regular security patching. The Company evaluates each cloud service on a case-by-case basis to determine if the solution offers cost efficiencies or other benefits.

Q. Please describe Exhibit A-107 (JDT-5).

A. Exhibit A-107 (JDT-5) is the Historical 13-month Average of IT Cloud Computing Prepaid Balance for Electric and Common for the actual 13-month balance ending September 30, 2019, and projected 13 months ending December 31, 2021. It provides a summary of the electric allocation of actual and projected IT Department operational expenditures. Specifically:

- Column A provides the IT cloud computing prepaid;
- 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-107 (JDT-5).

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 requesting projected working capital rate-making treatment, as referenced in Company witness Daniel L. Harry's testimony.

Q. How has the work required to meet cyber security requirements increased in the last five years?

A. The current and emerging cyber attack trends, and therefore cyber security requirements, have changed significantly over the past five years. Examples of this include ransomware and grid attacks. Five years ago, ransomware was a little-known attack, typically impacting individuals. Today, it is one of the greatest risks an organization faces, with real examples impacting Michigan, such as the ransomware attack on the Board of Water and Light in April 2016 (https://www.securityweek.com/michigan-power-and-water-utility-hit-ransomware-attack). Similarly, concern over attacks to utility infrastructure has become top of mind across the utility industry. As the security industry best practices change, the IT organization must strive to keep pace with the time and expense of retrofitting existing infrastructure and applications to meet those best practices.

Recently, the Company increased its cyber security focus and resources on protecting assets at key locations. The five areas of cyber security focus include: (1) secure network connectivity to the industrial control system's enterprise network; (2) security visibility through log collection, antivirus, and endpoint monitoring tools; (3) cyber maintenance, including patching, inventory, and change management; (4) identity and access management, including account and password management; and (5) infrastructure administration, such as hardware, operating system, and network support.

Q. Do cyber security requirements increase the frequency of keeping IT assets current?

A. Yes. Security patching has become a key control for any security program. Vendors regularly release patches. According to a 2019 survey of 15 similar utilities, most patch at least monthly. In 2018, Consumers Energy had two instances of highly critical patches that utilized the Company's ICS in order to ensure that patching was performed within ten days. In 2019, the Company had four such ICS events on a growing asset base. The need for security patches also increases the need to keep applications current. Vendors establish an end-of-life process for applications and, at some point, will no longer provide security updates or patches for earlier versions. Where the Company may have had more discretion in the past to defer upgrades, it now must ensure the appropriate upgrade or replacement frequency to meet security requirements. For Operational Technology ("OT") hardware, the number of Company devices requiring patching has increased by nearly 10 times between 2014 and 2019.

The Company closely tracks its performance in applying security patches and invests heavily in improving its protection of its IT assets. From January 2017 to September 2019, the Company reduced its average number of missing patches per workstation by 87%. From January 2016 to September 2019, the Company reduced its number of missing patches per server by 90%, demonstrating the Company's increased focus and time spent on maintaining the currency and security of its technology and data to protect the Company and its customers.

OPERATIONS O&M EXPENSES—MAINTAIN AND OPERATE EXISTING ASSETS

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

A. The Company uses Operations O&M expense to provide the required level of operational support, reliability, and security for technology investments deemed prudent in prior and current rate cases. Operations activities include system monitoring, break/fix activity, maintenance activity, hardware and software vendor support and services, cloud subscriptions and contracts, technology and application upgrades, security improvements, and other activities required to keep the Company's digital and information assets protected and performing at sufficient levels to obtain the committed value for the Company and its customers. The Company's customers have benefitted from the system stability and reliability that have resulted from the activities supported by IT Operations O&M expense. If the Company does not have sufficient funding to adequately support, maintain, and secure its existing technology assets, its customers and employees will experience interruptions in systems they rely on to contact and transact with the Company, view account information, receive electric services, receive accurate bills, maintain and operate the electric system, and make investments in the electric system that ensure safety and reliability.

Nearly half of the Company's IT and security operations costs are committed in contracts with vendors who provide software and hardware support and maintenance services so systems remain safe from mechanical and software failures and cyber intrusions. Lapses in support coverage caused by financial constraints expose the Company to unfavorable security and operational risks and issues.

Q. Please describe Exhibit A-104 (JDT-1).

A. Exhibit A-104 (JDT-1) is a Summary of Actual and Projected IT Operations O&M Expense for the Years 2018, 2019, 2020, and 12 months ending December 31, 2021. It provides a summary of the electric allocation of actual and projected IT Department operational expenditures. Specifically:

- Column A provides the Operations O&M expense category;
- Column B identifies the 2018 historical Operations O&M expense as $45,905,000;
- Column C identifies the 2019 projected Operations O&M expense as $43,596,000;
- Column D identifies the 2020 projected Operations O&M expense as $48,440,000;
- Column E identifies the 12 months ending December 31, 2021 projected Operations O&M expense as $49,287,000; and
- "Labor" line items include employee labor, and "Contracts" line items include hardware and software licenses and maintenance, staff augmentation, the Company's managed services contract, and other contracted services.

Q. Please describe the projected IT Department Operations O&M expense for 2020 or 2021.

A. The Operations O&M expense in 2020 of $48,440,000 and 2021 $49,287,000 is projected to be respectively 11.1% and 13.1% higher than 2019. The reason for the increase in 2020 and 2021 is the result of the continued investments in programs that both sustain and improve the experience customers have in interacting with the Company to maintain, improve, and secure critical enterprise systems that support operating the Company's electric grid, and prevent obsolescence and risk to business operations. Key drivers for the increase include: (1) cloud solutions for IT service management, customer analytics, disaster recovery ("DR"), and business continuity ($1,580,000); (2) project management, desktop automation, collaboration tools, and application development tools ($1,235,000); and (3) security application support ($335,000).

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

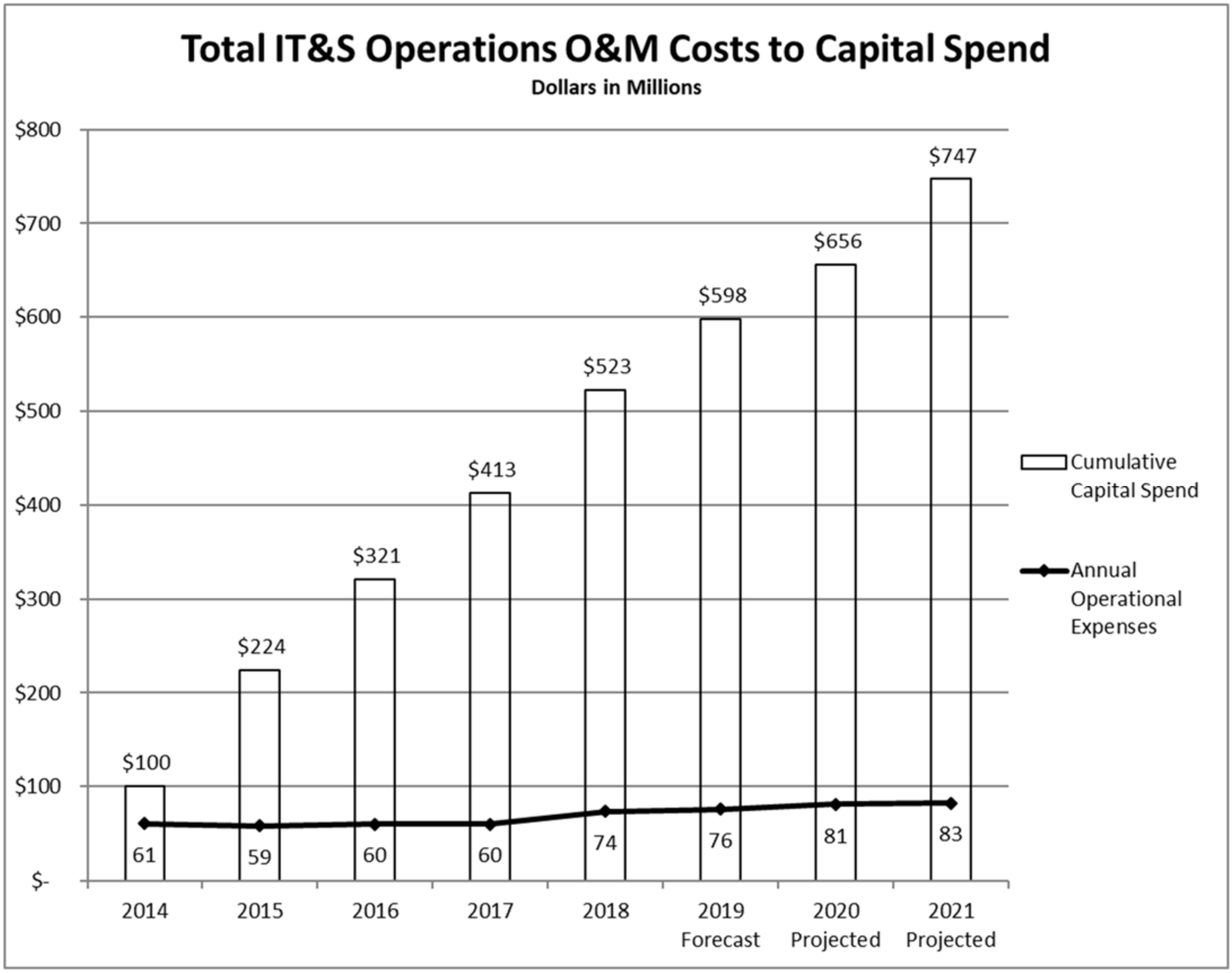
A. There is a variety of operational work required to keep IT and information assets protected from cyber threats. First, security tools must be kept functional on all relevant technology. These include software to collect logs, look for vulnerabilities, detect intrusions, and provide antivirus and encryption services. Second, systems must be patched on a regular basis, typically monthly. Vendors regularly release security updates that then must be tested to ensure these updates do not introduce negative impacts to Company-specific configurations, and then deployed to associated technology assets. Third, as security best practices change, IT teams must make changes to existing systems to meet new security requirements.

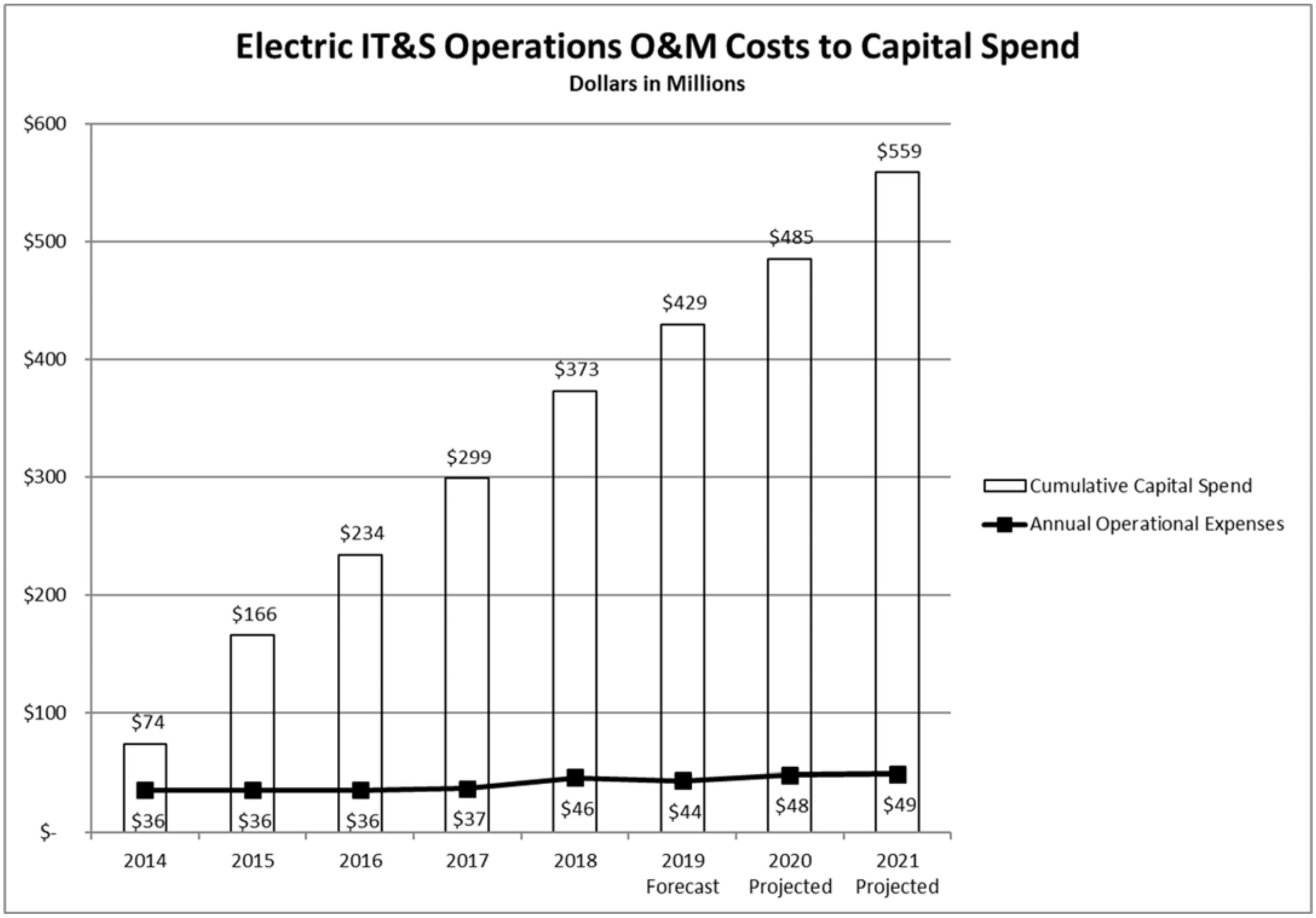
Q. What is another example of operational work for cyber security beyond patching?

A. As security best practices or regulatory requirements shift, legacy applications and their underlying infrastructure often need to be changed to meet new standards. For instance, in response to ongoing ransomware attacks across all industries, the Company has been properly securing all operating system and application accounts with elevated privileges as it is these types of accounts that allow cyber criminals the ability to execute ransomware attacks. The account management practices for these accounts were perfectly acceptable at deployment, but changing requirements dictate the need for updated practices.

Q. What is the trend for the Company's IT Operations O&M expenses?

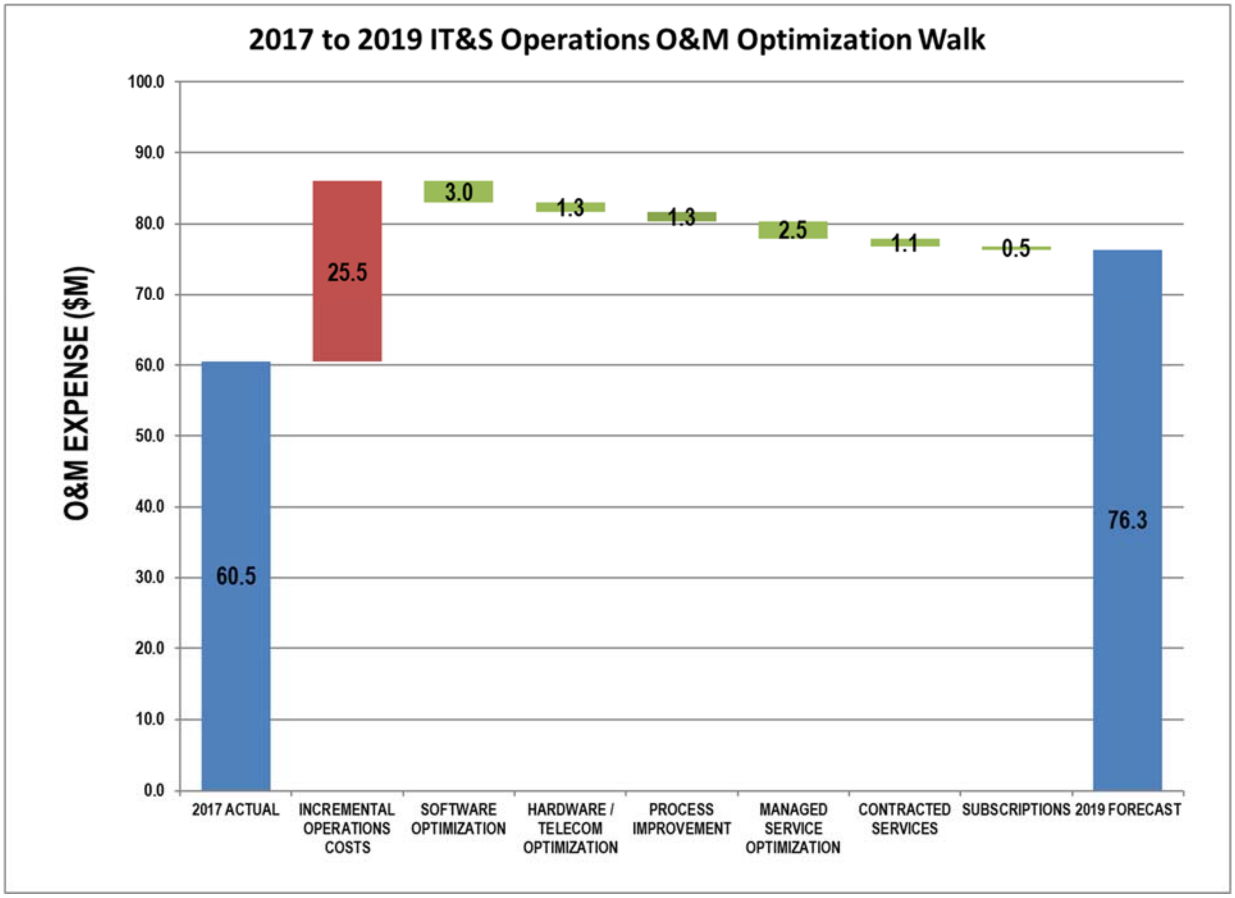
A. Both the growing work requirements for cyber security described above and the growing base of IT assets in the Company have been contributing to higher Operations O&M expense and a sustained moderate, but upward trend. The graphs below show the IT and security Operations O&M costs relative to the cumulative capital spend on IT assets (total Company and electric). The graphs demonstrate the upward trend in the Operations O&M required to keep new and existing capital investments secure and reliable and maintain an increasing number of cloud-based solutions. The increases would have been higher without cost-reduction efforts undertaken by the Company, described below.


Total IT&S Operations O&M Costs to Capital Spend
Dollars in Millions
$800
$700
$600
$500
$400
$300
$200
$100
$-
$100
$224
$321
$413
$523
$598
$656
$747
61
59
60
60
74
76
81
83
2014
2015
2016
2017
2018
2019 Forecast
2020 Projected
2021 Projected
Cumulative Capital Spend
Annual Operational Expenses



Q. How has the IT Department controlled the rate of increase in Operations O&M expenses?

A. The IT Department has undertaken a continued focused effort to optimize total Operations O&M expense required to maintain the Company's technology assets. As demonstrated in the graph below, investments in technology would have increased the total operational costs by $25.5 million from 2017 to 2019. Through efforts to reduce software and hardware maintenance agreements, improve processes for labor efficiency, and reduce managed services contract costs, IT was able to offset O&M increases with a sustained $9.7 million reduction, limiting the increase to $15.8 million over that period.

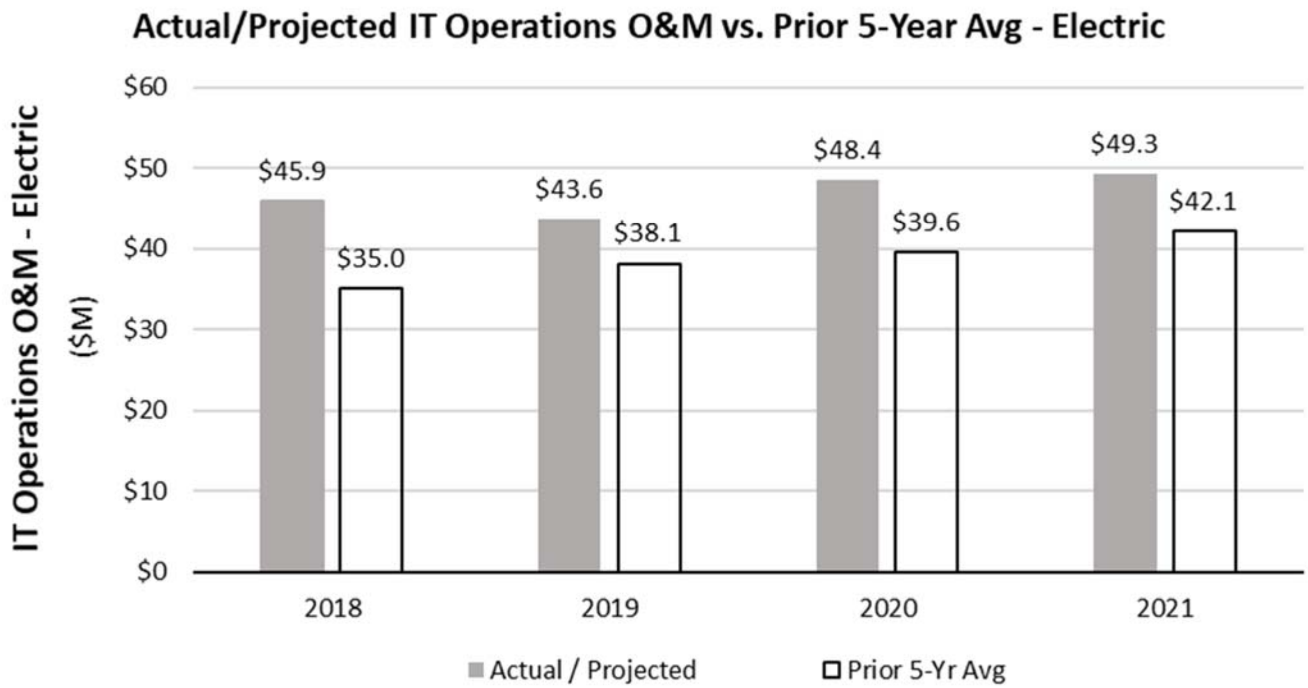


Q. Does the use of a five-year average to project the Company's IT Operations O&M expenses put the Company and service to its customers at a higher risk?

A. Yes, significantly. The level of IT Operations O&M expense is closely linked to increasing security requirements, a growing technology asset base through prior capital investments, and increasing use of cloud solutions. Collectively, these are not adequately supported using a five-year average. Typically, the Company has received final rulings in favor of all, or a majority of, the IT capital expenditures requested in previous rate cases. To fully and appropriately support the assets created by those capital investments that have been deemed prudent, and keep them secure, the Company needs to be approved to spend the specific IT Operations O&M expense requested. IT assets have increased every year for the past five years. That growth curve, and the cumulative asset base, does not support a historic five-year average method of estimating operations levels. Additionally, the Company projects an increased investment in cloud solutions that have a higher level of O&M spend not found in the historic five-year period. While the Company is working hard to contain the growth in technology support costs as demonstrated in the above graphs, the five-year average method is significantly less than the actual need and substantially understates the O&M needed to support the current and projected asset base. Approval based on a five-year average would limit the Company's ability to adequately support and maintain the capital expenditures made previously on behalf of its customers.

If the Company is not able to operate, support, secure, and maintain the technology systems it already has due to lack of operating expense, it expects to experience reliability and cyber security issues. If maintenance fees are not paid to software vendors, for example, vendors no longer provide security patches, expert troubleshooting advice, or upgrades that make it possible to run on newer operating systems and databases. Keeping the Company's systems secure and reliable is so important that the Company spent $10.9 million more than the prior five-year average for electric IT Operations O&M in 2018. The Company forecasts spending $5.5 million more than the five-year average in

2019, and the trend continues in 2020 and 2021. This is shown in the chart below. If approval is received based on a five-year average, this model is not sustainable.



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

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

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

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

A. Upgrading applications, operating systems, and database management systems is essential to delivering safe, reliable, and affordable service to the Company's customers. New versions of technology enable the Company to maintain vendor support, remediate security vulnerabilities, address defects that impair stability and functionality, and address version interdependencies and compatibility between systems.

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

A. Technologies that are not upgraded are often no longer supported by vendors, which increases security risk, as security patches are regularly released by vendors based on known vulnerabilities. Security patches may not be backwards compatible with older versions of software and hardware, thus preventing their installation and thereby increasing the risk of a significant cyber event impacting Company operations and service to its customers.

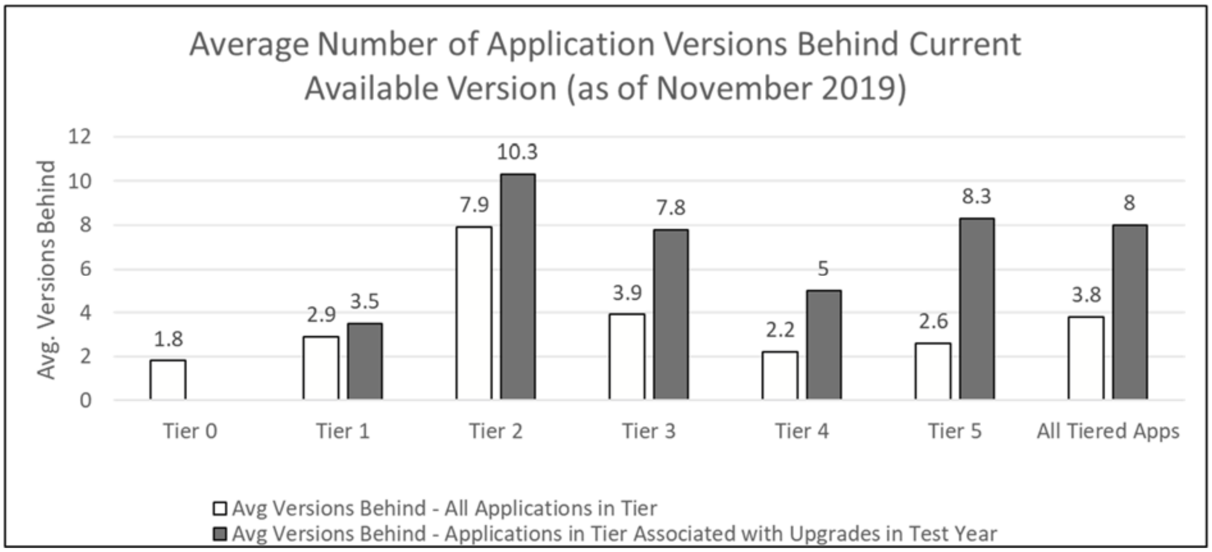
Q. How does the Company determine which systems need to be upgraded?

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

Historically, the Company has not been authorized the O&M needed in rates to maintain and keep systems current. Technical obsolescence continues to increase, and the Company is in a position of playing catch-up, adding risk that a significant cyber security or technical issue could not be remediated or mitigated, causing direct impact to Company operations, its customers, or both. The Company has had to prioritize the most important technology and is now at the point where some of the most important technology systems cannot be kept current and are at risk. The Company is also prioritizing operational support over new investments when resources are scarce, thus putting the various investment plans that support the IRP and EDIIP at risk.

Q. Please describe the risk level of the Company's IT systems based on software versions.

A. The Company has six tiers (designated "0" through "5") to categorize application importance. Tier designation is based on the criticality of the application to business operations as defined for DR and business continuity purposes, with Tier 0 as the first priority to restore in the event of a disaster. Using these application tiers, the graph below shows the average number of versions that the Company is behind from the vendors' most current versions for applications in that tier. For example, the applications in Tier 2, which are applications associated with emergency response and have high financial impact when unavailable, are an average of 7.9 versions behind the vendors' most current versions. The graph also shows the same version information for applications that have associated upgrades planned in the test year in this case. For example, Tier 2 applications with associated upgrade projects in this case are an average of 10.3 versions behind the vendors' current version. The application currency projects requested in this case address applications that are farthest behind.



Generally, applications that are further behind the vendors' current available version are at higher risk of not having vendor support, which includes the ability to obtain and apply security patches for the applications. The graph demonstrates the Company's focus on investing first in upgrading those applications at greatest risk of obsolecense and support issues. The version variances shown in the graph are certain to widen as vendors release new software versions before the test year begins, increasing the risk level for the Company. While applications in Tiers 0 through 5 are considered the most important, there are many other applications outside of these tiers that need to be upgraded on a regular basis for security and reliability, including underlying platforms, such as infrastructure or desktop operating systems, and databases.

Q. Please describe Exhibit A-105 (JDT-2).

A. Exhibit A-105 (JDT-2) is a Summary of Actual and Projected IT Investments O&M Expenses for the Years 2018, 2019, 2020, and 12 months ending December 31, 2021. It provides a summary of the electric allocation of actual and projected IT Department Investments O&M expenditures. Specifically:

- Column A provides the Investments O&M expense category;

- Column B identifies the 2018 historical Investments O&M expense as $16,103,000;
- Column C identifies the 2019 projected Investments O&M expense as $13,912,000;
- Column D identifies the 2020 projected Investments O&M expense as $17,012,000;
- Column E identifies the 12 months ending December 31, 2021 projected Investments O&M expense as $21,884,000; and
- "Labor" line items include employee labor, and "Contracts" line items include hardware and software licenses and maintenance, staff augmentation, and other contracted services.

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

A. Yes. The preliminary project stage activities are essential to ensure the Company makes prudent investments in technology. The activities cover much of the work included in the Company's investment planning for IT projects. This includes identifying high-level business requirements, determining whether the functionality needed is already present in the Company's IT environment, exploring alternatives, identifying performance and security requirements, working with software vendors and cloud solution providers to demonstrate the effectiveness and security of their products and services, and developing the business case with project costs and benefits to confirm whether a proposed project should be approved for development and implementation.

Q. Is the investment planning activity speculative?

A. No, it is not speculative. In fact, the outcome of this investment planning process is the very information ordered by the MPSC in Case No. U-18238 as part of the rate case filing requirements for IT and OT. The required information includes a project description and functionality of the system, project timelines and spending plans, project benefits, project timeline including expected implementation date, a description of alternatives considered and rationale behind the decision, cost benefit ratio, and project business case.

During this phase, the Company spends the necessary time on up-front planning and due diligence for the technology investment, as is done with any other class of assets in the Company. As an example, to more effectively monitor and control generation, transmission, and high voltage distribution circuits, the Company must upgrade its High Voltage Distribution ("HVD") Supervisory Control and Data Acquisition ("SCADA") system. The Company has already spent time on up-front planning to confirm the high-level scope, needs, and alternatives assessment. More time must be spent to evaluate vendor solutions and organize the project, which is necessary time spent, and not speculative.

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

A. Yes, the Company should be allowed recovery for this up-front planning activity. Beyond being necessary to meet the rate case filing requirements, according to the Project Management Institute ("PMI"), planning is necessary regardless of the project delivery methodology. The PMI's Project Management Body of Knowledge ("PMBOK") and Agile Practice Guide both cite the need to include planning for successful project implementation. It is also in the best interest of the Company's customers that the Company perform these investment planning activities to ensure the investment idea provides sufficient value to justify the expenditure. The Company catalogs many ideas, but not all are feasible or even warrant investment planning. Only those with the highest expected value even reach the planning phase. The work required by the MPSC for technology investment planning is both reasonable and prudent, and does have costs associated. The Company should receive recovery for this required expense.

Q. Would it be more accurate to use a five-year average to project the Company's IT Investments O&M expenses?

A. No. The level of IT Investments O&M expense is closely coupled with the projected capital expenditures for IT and the upgrade and replacement cycles for existing assets. Typically, the Company has received final rulings in favor of all, or a majority of, the IT capital expenditures requested in previous rate cases. To fully and appropriately execute plans to spend the capital that has been deemed prudent to deliver value to its customers, keep its technology assets at reasonable levels of currency and security, and adhere to the FASB ASC 350-40 guideline for project activities that should be expensed, the Company should be approved to spend the specific and forward-looking IT Investments O&M requested for the test year period, versus a backward-looking average. Approval based on a five-year average, which would be lower than the requested amount in this case, would not allow the Company to make the necessary and prudent capital expenditures to achieve the outcomes of the EDIIP, improve customer service, and keep its systems current for security and reliability. Additionally, the Company projects an increase in cloud solutions, which often have a higher level of Investments O&M spend not found in the historic five-year period.

INVESTMENTS CAPITAL EXPENDITURES

Q. Please describe the capital expenditures shown on Exhibit A-12 (JDT-3), Schedule B-5.3.

A. Exhibit A-12 (JDT-3), Schedule B-5.3 identifies the electric allocation of projected capital expenditures to procure, install, and implement the software and infrastructure requested in this testimony to meet business requirements. Specifically:

- Column A provides the program designation for the capital expenditures, using programs that have been used historically to categorize IT projects:
  - Upgrades and replacements (enterprise);
  - Upgrades and replacements (business partner);
  - Security;
  - IT service delivery;
  - Enhancements;
  - Business partner functionality; and
  - Architecture;
- Column B identifies the 2018 historical capital expenditures as $74,245,000;
- Column C identifies the 2019 projected bridge year capital expenditures as $56,370,000;
- Column D identifies the 2020 projected bridge year capital expenditures as $55,586,000;
- Column E identifies the 24 months ending December 31, 2020 projected bridge year capital expenditures as $111,956,000; and
- Column F identifies the 12 months ending December 31, 2021 projected test year capital expenditures of $73,758,000.

Q. Please explain Exhibit A-106 (JDT-4).

A. Exhibit A-106 (JDT-4) identifies the electric allocation of projected capital and O&M expenditures to procure, install, and implement the software and infrastructure requested in this testimony to meet business requirements. Both O&M and capital are required to complete the projects included in the test year. This exhibit provides details regarding all projects included in this rate case filing for the IT Department. Specifically, within this exhibit:

- Column A provides the year of spending for this line item project;
- Column B identifies the project name associated with each line item capital expenditure for the applicable year;
- Column C identifies the IT program category;
- Column D identifies the Federal Energy Regulatory Commission ("FERC") category relative to the line item project's asset type;
- Column E provides a synopsis of the project, including the project description and information on project scope, functionality, and benefits;
- Column F identifies the project's implementation date;
- Column G provides the project's cost/benefit ratio;
- Column H provides the project's electric portion total capital expenditure for the applicable year;
- Columns I through M provide the details of categorical spend that sum to the total line item Project Capital Spend for the applicable year broken down by:
    - Software costs (I);
    - Material costs (J);
    - Labor costs (K);
    - Contractor costs (L); and
    - Overhead and other costs (M);

- Column N provides the project's electric portion total O&M spend for the applicable year; and
- Columns O through S provide the details of categorical spend that sum to the total line item Project O&M Spend for the applicable year by the following categories (categorical spend is not available for projects before 2019):
  - Software costs (O);
  - Material costs (P);
  - Labor costs (Q);
  - Contractor costs (R); and
  - Overhead and other costs (S).

Q. Please explain the difference between Exhibits A-12 (JDT-3), Schedule B-5.3; A-106 (JDT-4); and A-108 (JDT-6).

A. Exhibit A-12 (JDT-3), Schedule B-5.3; A-106 (JDT-4); and A-108 (JDT-6) are all capital expenditure exhibits that display different views to address the different requirements needed by the MPSC, as well as the IT Department, as outlined below:

- Exhibit A-12 (JDT-3), Schedule B-5.3 is a high-level summary of capital expenditures by year, by program, and by categorical spend;
- Exhibit A-106 (JDT-4) is an all-inclusive exhibit displaying every detail of each project over the four-year time periods of 2018, 2019, 2020, and 2021; and
- Exhibit A-108 (JDT-6) provides specific details for the test year 2021 that fulfills the MPSC's Rate Case Part III Filing Requirements, as well as providing details for each IT capital investment project request as described in testimony.

<u>INVESTMENT IDENTIFICATION, PRIORITIZATION, AND APPROVAL</u>

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

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

IT project approvals follow the corporate planning processes for inclusion in the Company's business plan. After sponsor approval, individual projects are prioritized based on an evaluation of the benefits, costs, customer value, and alignment with Company goals through a series of reviews by cross-functional business teams. The highest-ranking projects within the level of IT funding approved through the Company's budget process are selected for implementation and approved by each business area, followed by approval of the overall IT budget by the senior officer team. Due to the rapid pace of technology change and quickly changing business conditions, it is difficult to predict with 100% accuracy the exact projects that will be completed over the course of the year. Emergent projects are identified and vetted through IT and the affected internal business areas throughout the year as business objectives, Company goals, and customer needs and expectations evolve.

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

A. IT's investment forecasts begin with a Rough Order of Magnitude ("ROM") estimate. The Company follows a ROM estimating process similar to that outlined by the PMI in its PMBOK, where actual project costs may be in the range of -25% to +75% of the ROM estimate. ROM estimates are typically determined by technology and subject matter experts inside and outside the Company in comparison to similar historical projects. From that point, investment forecasting depends on the method used to deliver the intended solution. In the case of Agile delivery, which makes up over 40% of releases delivered by IT, the project team targets the delivery of the highest business value capabilities within the projected funding. In the case of traditional waterfall delivery, once the formal design of a project has concluded, IT subject matter experts perform a detailed definitive estimate for execution. Ideally, the definitive estimate would be close to the ROM estimate developed much earlier for project prioritization and budgeting decisions. However, based on the additional information gathered during the planning and design phases, the definitive estimate is likely to be different. The PMBOK provides guidance that a project's actual costs are narrowed from a range of -25% to +75% of the ROM estimate to a range of -5% to +10% of the definitive estimate. Factors that arise during the project life cycle, such as resource needs to complete a project, changes in project schedule that shift spending between years, and changes in project scope or complexity, that may result in funding needs being lower or higher than initially estimated through the ROM process.

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

A. 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. Most projects in the test year have been through up-front planning activities in which the start dates for the Plan, Define, Execute, and Close phases and Go-Live dates have been projected. When a project begins the Plan phase, the project manager will develop a more specific project plan that includes progressively more detail as the project moves through its different phases. In the case of projects executed using Agile methods, a high-level plan will be developed at the start of the project that includes an estimated number of time-bound delivery cycles, or sprints, in which the targeted scope backlog will be delivered.

INVESTMENT PROJECTS

Q. Please provide a breakdown and description of the various IT investment project areas to be highlighted in testimony.

A. Costs, descriptions, benefits, alternatives, and other relevant project information for each individual project can be found in Exhibit A-106 (JDT-4). The IT investment projects are grouped into the following areas for explanation in testimony:

- **Electric Grid Integration** ("EGI") projects that are necessary components to enable the Company's full electric distribution and supply strategy as outlined in our EDIIP and IRP;
- **Customer Experience and Operations** ("CE&O") projects that enable the Company to comply with regulatory billing changes, improve billing functionality, improve customer satisfaction, and increase the Company's ability to serve customers within the channel of their choice and improve the experience of customers in completing self-service transactions within that channel;
- **Corporate and Enterprise** projects that support internal departments of the Company crucial to running an efficient business for customers such as Treasury; Tax; Legal; Human Resources; Governmental, Regulatory and Public Affairs; and Finance;
- **Operations Support** projects that enhance the capabilities of the Company's supply chain function;
- **Asset Refresh Program** ("ARP") projects implemented to maintain the currency, reliability, and security of the Company's IT infrastructure that is core to all Company operations, including customer service, and maintaining a safe, reliable, and affordable electric system;
- **Upgrades and Application Currency** projects implemented to maintain the currency, reliability, and security of the Company's IT applications and enterprise software supporting all Company operations, including customer

service, and maintaining a safe, reliable, affordable electric distribution infrastructure plan;

- **Digital Foundations and Capabilities** projects to create the technology platforms, tools, processes, and frameworks that enable EDIIP and customer service outcomes; and

- **Security** projects that enable physical and cyber security for the Company's customer information, employees, IT applications and infrastructure, and Company facilities and assets.

Q. Please explain the projects enabling the EGI.

A. Below are the projects enabling the EGI. A full synopsis of each project with its value is included in the testimony of Company witnesses Richard T. Blumenstock, Scott A. Hugo, and Keith G. Troyer, as indicated below.

Project	Capital	O&M	Witness
Electric Underground Conflation	$392,000	$11,000	Blumenstock
Field Contractor Work Management Technology Enablement	$1,937,715	$171,680	Blumenstock
GIS-Integrated Design	$0	$349,206	Blumenstock
GM - GIS Connectivity Model Integration	$0	$25,000	Blumenstock
Electric Grid Telecom Device Management	$91,000	$146,600	Blumenstock
One Call Ticket Risk Analysis Model for Damage Prevention	$580,220	$125,202	Blumenstock
Work Management Scheduling Analytics and Reporting	$966,348	$149,176	Blumenstock
Electric Agricultural Services Data Base	$292,000	$32,850	Blumenstock
Field Mapping and Graphics	$1,428,719	$23,852	Blumenstock
Electric Infrastructure Attachments	$727,000	$80,500	Blumenstock
Real Time Electric System Access in the Field	$0	$252,000	Blumenstock
Electric Distribution Asset Management	$1,984,000	$751,000	Blumenstock

Replacement of Testing Software for the Electric Meter Technology Center	$0	$24,280	Blumenstock
Renewables Supervisory Control and Data Acquisition Overlay	$813,157	$21,705	Hugo
Centralized Demand Response Management	$1,293,000	$127,000	Troyer
MISO Market User Interface Changes	$65,000	$68,000	Troyer
Centralized Demand Response Management Assessment	$0	$305,700	Troyer
Electric Interconnection Billing and Payment	$1,095,000	$148,000	Troyer
MISO Market System Replacement	$440,000	$66,000	Troyer

Q. Please explain the projects included in the CE&O area.

A. Below are the projects included within the CE&O area. A full synopsis of each project with its value is included in the testimony of Company witness Steven Q. McLean.

Project	Capital	O&M
Customer Operations Commercial Theft	$311,842	$131,784
Large Customer Rate Tool	$0	$115,500
Summer Peak Use Rate - Release 2	$0	$116,000
On-Bill Financing	$1,336,508	$138,270
Voxai Survey Tool	$166,272	$7,920
Dashboard Redesign	$2,528,027	$164,670
Cross-Channel Analytics	$0	$79,200
Data Lake Entry	$401,911	$36,135
Website Redesign	$3,184,331	$434,445
Landlord Small Business Portal	$2,094,646	$149,111
Business Customer Interval Web Portal	$0	$165,000

Move In/Move Out Digital Redesign	$1,105,813	$46,215
Bill Design and Delivery Transformation	$5,209,551	$926,970
Move In Move Out Version 3.0	$1,462,828	$175,973

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

A. Below are short descriptions for the projects included within the Corporate area. A full synopsis of each project is included in the direct testimony of Company witness Karen M. Gaston.

Project	Capital	O&M
Accounts Payable ("AP") Automation	$0	$104,280
EHS Compliance	$0.00	$63,601
Enterprise Content Management - Managing Business Records	$251,486	$486,420
Financial Planning Transformation - Intake and Monthly Plan Management	$3,407,190	$287,100
HR - 2020 Union Changes	$0	$177,679
Rates Case Implementation	$0	$172,135
Workforce Connect – Talent Enablement	$329,946	$1,412,714
Rate Design and Evaluation Tool	$545,698	$181,576

Q. Please explain projects included in the Operations Support Area.

A. Below are explanations of projects included within the Operations Support Area:

- The **ServiceNow Customer Service Management ("CSM")** project requires $62,905 in O&M. This project will implement the CSM module of ServiceNow to enable the recently defined Supply Chain ("SC") service delivery model to support SC optimization. This project will provide value to the Company and its customers through: (1) waste elimination; (2) cost savings; (3) maturing processes; and (4) movement to a sustainable service delivery model to continually improve the customer experience. This project specifically will enable the newly designed processes and service delivery model as it will: (1)

enhance the delivery of SC services to both internal customers and suppliers; (2) include an integrated knowledge base and case management systemwhich improves the customer experience by having one place to go for information and help; and (3) provide standard workflow and funnel the previously disparate intake channels for SC support into one solution. This technology solution is the backbone of an SC Support Center and will enable: (1) better management of work; (2) more efficient and accurate response to questions; and (3) improved satisfaction of internal customers and external suppliers. The scope of the project includes: (1) configuring and implementing the CSM ServiceNow module for Supply Chain processes; (2) implementing self-service, including a virtual chat agent; (3) configuring and implementing workflow for case resolution; (4) implementing management dashboards and reporting; and (5) developing and implementing simple integrations to and from SAP. The alternatives considered include: (1) continue to use manual processes to manage the SC service delivery model; (2) consider alternate service delivery providers; (3) develop a home-grown application to provide the same functionality; and (4) extend the company's ServiceNow implementation with the CSM module. With the first alternative, many of the benefits captured in the overall SC optimization business case conducted last year would not be sustainable if the SC service delivery model was not improved. Additionally, success requires building and gaining trust from business partners to shift work to the strategic procurement efforts with the most opportunity for savings. The second alternative was ruled out because the Company already has a ServiceNow instance in IT, and it would be very costly to find a different but redundant customer service application. The third option was dismissed as it would not only be expensive due to the complexity inherent in this option, but it would significantly delay the timeline without increasing benefits. Selecting the fourth option enables the Company to save the costs inherent to creating a new relationship with a vendor, and address the gaps identified in the current SC service delivery process.

- The **Contract Life Cycle Management** project requires $30,483 in capital and $80,190 in O&M. This project will implement a new contract management solution to manage the life cycle of contracts. This project will provide value to the Company and its customers through: (1) an improved user experience; (2) standardization of the supply chain platform for sourcing and contracts; (3) reduction of manual steps to select approvers; (4) integration with SAP; and (5) reduced annual subscription fee for the solution. The scope of this project includes: (1) implementing the new contract life cycle management solution; (2) integrating this solution with SAP supply chain; (3) transitioning the active contract information from current solution; (4) discontinuing use of the current solution for contract management. As part of the review process, alternatives considered included: (1) delay implementation of a new solution; or (2) remain on the current platform. The alternative to delay implementation was not selected because it defers a significant reduction in support costs and opportunities to reduce manual efforts. The alternative to remain on the current platform was not considered due to the intensive manual effort to route physical documents for approvals, inability to streamline source-to-pay ("S2P") workflows, and costly support model. The option to implement a new contract management life cycle management cloud-based solution was chosen after evaluation of leading vendor software applications for S2P solutions through a request for information and vendor demonstration process.

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

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

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

- Michigan.gov, Information Technology Equipment Life Cycle. https://www.michigan.gov/documents/dtmb/Sec._829_IT_Lifecycle_Report_2018_619021_7.pdf

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

Q. Please explain the ARP and infrastructure projects.

A. The following are the ARP and infrastructure projects:

- The **ARP — OT Support** project requires $502,403 in capital and $34,568 in O&M. This project will replace dated and obsolete servers and workstations. This project creates value by maintaining the currency of the Company's IT infrastructure and core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure. The project scope consists of: (1) the annual replacement of compute hardware under the program, and (2) installing additional new compute capacity to account for organic growth requirements. Extending maintenance is not a viable alternative as current systems do not provide sufficient capacity for new electric system support capabilites.

  Following are the projected capital costs for ARP – OT Support project attributable to the electric business for 2020 and 2021 test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Test Year Dollars	Electric Allocation Dollars
Servers	$15,000.00	10	30	$150,000.00	$450,000.00	$256,680.00
Tape Libraries	$25,000.00	2	0	$50,000.00	$0.00	$0.00
Hyper-Convered Solution	$100,000.00	2	0	$200,000.00	$0.00	$0.00
Switch	$15,000.00	4	5	$60,000.00	$75,000.00	$42,780.00
Firewall	$30,000.00	0	4	$0.00	$120,000.00	$68,448.00
Software, labor, contractor and overhead and other costs				$167,900.00	$235,791.00	$134,495.19
Total Materials Electric Allocation				$627,900.00	$880,791.00	**$502,403.19**

Following are the actual and projected capital costs for ARP – OT Support project attributable to the electric business for 2018 and 2019 in the table below.

Units	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Electric Allocation Dollars	2019 Electric Allocation Dollars
698-2700 MHZ 8-10 DB LOG	$101.28	20	0	$2,025.52	$0.00	$1,178.85	$0.00
698-896/1700-2700 MHZ	$78.78	10	0	$787.81	$0.00	$458.51	$0.00
Antenna	$136.45	60	0	$8,187.18	$0.00	$4,764.94	$0.00
Antennas - SCADA	$96.87	0	110	$0.00	$10,655.29	$0.00	$6,077.78
Firewalls- Hydro Site	$1,548.32	0	12	$0.00	$18,579.87	$0.00	$10,597.96

Switches for Firewalls-Hydro Site	$885.01	0	8	$0.00	$7,080.09	$0.00	$4,038.49
Connected Grid 2G/3G/4G LTE GRWIC	$1,070.00	0	4	$0.00	$4,279.98	$0.00	$2,441.30
Firepwr Mgmt Ctr 2500C Appliances	$17,870.38	4	0	$71,481.50	$0.00	$41,602.23	$0.00
Modems -IST 4451 SEC BUNDLE	$12,320.49	3	0	$36,961.48	$0.00	$21,511.58	$0.00
NETWORK EQUIPMENT	$4,667.71	0	2	$0.00	$9,335.42	$0.00	$5,324.92
PWR SPPLY - NTWK EQUIP PERIPHERALS	$169.32	0	4	$0.00	$677.29	$0.00	$386.33
CONNECT 4G X BOOSTER KIT	$884.93	1	0	$884.93	$0.00	$515.03	$0.00
DC/DC POWER SUPPLY 6V	$35.17	1	0	$35.17	$0.00	$20.47	$0.00
Curved Monitor	$1,166.00	8	0	$9,328.00	$0.00	$5,428.90	$0.00
SCADA	$1,131.98	20	0	$22,639.62	$0.00	$13,176.26	$0.00
ROUTERS	$652.88	20	307	$13,057.53	$200,433.09	$7,599.48	$114,327.03
HIPswitch Appliance	$8,051.51	1	0	$8,051.51	$0.00	$4,685.98	$0.00
Tap Cartridge	$36.26	150	0	$5,439.64	$0.00	$3,165.87	$0.00
Hypervisors	$24,419.22	6	0	$146,515.33	$0.00	$85,271.92	$0.00
Switch (32 port)	$4,390.40	7	0	$30,732.79	$0.00	$17,886.48	$0.00
Standard OT Laptop	$2,551.13	7	0	$17,857.93	$0.00	$10,393.32	$0.00
Wall Monitor	$1,965.24	0	1	$0.00	$1,965.24	$0.00	$1,120.97
Server	$4,250.00	0	1	$0.00	$4,250.00	$0.00	$2,424.20
Antennas	$85.99	60	0	$5,159.40	$0.00	$3,002.77	$0.00
Servers	$49,449.92	4	0	$197,799.69	$0.00	$115,119.42	$0.00
Servers	$9,507.96	0	7	$0.00	$66,555.71	$0.00	$37,963.38
Industrial RTU 2M NVRAM 64M D	$1,883.00	24	0	$45,191.88	$0.00	$26,301.67	$0.00
SANs (2x 20TB)	$57,963.14	0	2	$0.00	$115,926.27	$0.00	$66,124.34
Sentinal Monitoring Appliance	$22,525.00	0	1	$0.00	$22,525.00	$0.00	$12,848.26
Severs/SAN’s	$57,754.65	6	0	$346,527.90	$0.00	$201,679.24	$0.00
SFP	$53.27	80	0	$4,261.20	$0.00	$2,480.02	$0.00
SHREDDER/DEGAUSER HARDWARE	$27,701.76	1	0	$27,701.76	$0.00	$16,122.42	$0.00
SMARTNET NETWORK EQUIP MAINTENANCE (SFP)	$197.46	0	2	$0.00	$394.92	$0.00	$225.26
Switches	$10,018.05	0	2	$0.00	$20,036.09	$0.00	$11,428.59
Switches	$7,353.61	12	0	$88,243.26	$0.00	$51,357.58	$0.00
Thin Client	$975.77	0	3	$0.00	$2,927.31	$0.00	$1,669.74
Tier 5 (2,501 - 5,000) Switch 250gd a	$4,243.59	2	0	$8,487.17	$0.00	$4,939.53	$0.00
Tier 5 Hipswitch Modem	$1,397.32	100	0	$139,732.40	$0.00	$81,324.26	$0.00

SN6000 ROUTER AND SET UP	$427.18	0	4	$0.00	$1,708.72	$0.00	$974.65
4G LTE Modems for SCADA	$1,088.97	12	0	$13,067.68	$0.00	$7,605.39	$0.00
Workstation	$3,571.59	5	0	$17,857.93	$0.00	$10,393.32	$0.00
Software, labor, contractor and overhead and other costs				$459,727.19	$187,880.78	$267,561.22	$107,167.20
Total Electric Allocation				$1,727,743.40	$675,211.07	**$1,005,546.66**	**$385,140.39**

- The **ARP — Operational Technology Storage Area Network ("SAN")** project requires $278,355 in capital and $30,360 in O&M. This project will refresh aging SAN with Unity SANs. This project creates value by maintaining the currency of the Company's IT infrastructure and core enterprise software that are utilized to support and enhance customer interactions, as well as ensure the stability of technology for business operations that are in service of the Company's customers. The project scope consists of: (1) annually replacing SAN hardware under the program; and (2) installing additional new compute capacity to account for organic growth requirements. The alternative considered was to purchase extended maintenance. This alternative was not chosen due to the risk of increased downtime of critical infrastructure and maintenance costs. The cost of bringing personnel on site to make system corrections in the event of a serious interruption is higher than the cost of buying new.

  Following are the projected capital costs for ARP – OT SAN project attributable to the electric business for 2020 and 2021 test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Test Year Dollars	Electric Allocation Dollars
Unity Storage - 20TB	$65,000.00	3	0	$195,000.00	$0.00	$0.00
Unity Storage - 50TB	$125,000.00	2	0	$250,000.00	$0.00	$0.00
Data Domain	$83,000.00	0	5	$0.00	$415,000.00	$236,716.00
Software, labor, contractor and overhead and other costs				$273,000.00	$73,000.00	$41,639.20
Total Electric Allocation				$718,000.00	$488,000.00	**$278,355.20**

- The **ARP — Printer Asset Management ("PAM")** project requires $715,356 in capital and $11,997 in O&M. This project will replace printers, plotters, and multi-function printing devices. 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. The project scope consists of the annual replacement of printer assets under this program. The alternatives considered for the project included looking at refresh cycles from three to seven years and 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 result in additional unneeded expense for replacement of assets that were still in peak operating condition, and anything greater than five years, including running the asset to failure, would result in additional expenses in maintenance of the equipment and downtime, negatively impacting employee productivity.

Following are the projected capital costs for ARP – PAM project attributable to the electric business for 2020 and 2021 test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Test Year Dollars	Electric Allocation Dollars
Black and White Printer	$1,181.90	1	0	$1,181.90	$0.00	$0.00
Color Laser Multifunction Printer	$1,664.20	23	19	$38,276.60	$31,619.80	$21,906.20
Color Wide Format Printer	$8,204.40	4	15	$32,817.60	$123,066.00	$85,260.12
Black and White Printer	$2,757.06	0	1	$0.00	$2,757.06	$1,910.09
Color Laser Multifunction Printer	$15,537.48	0	2	$0.00	$31,074.96	$21,528.73
Color Laser Multifunction Printer	$3,021.00	5	26	$15,105.00	$78,546.00	$54,416.67
Color Laser Multifunction Printer	$5,596.80	18	36	$100,742.40	$201,484.80	$139,588.67
Color Laser Multifunction Printer	$6,191.46	27	30	$167,169.42	$185,743.80	$128,683.30
Color Laser Multifunction Printer	$7,303.40	15	37	$109,551.00	$270,225.80	$187,212.43
Software, labor, contractor and overhead and other costs				$108,040.08	$108,039.78	$74,849.96
Total Electric Allocation				$572,884.00	$1,032,558.00	**$715,356.18**

Following are the actual and projected capital costs for ARP – OT PAM project attributable to the electric business for 2018 and 2019 in the table below.

Units	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Electric Allocation Dollars	2019 Electric Allocation Dollars
Black and White Printer	$1,181.90	16	4	$18,910.40	$4,727.60	$13,188.11	$3,275.28
Color Laser Multifunction Printer	$1,664.20	37	58	$61,575.40	$96,523.60	$42,942.68	$66,871.55
Color Wide Format Printer	$8,204.40	6	5	$49,226.40	$41,022.00	$34,330.49	$28,420.04
Color Laser Multifunction Printer	$3,021.00	15	13	$45,315.00	$39,273.00	$31,602.68	$27,208.33
Color Laser Multifunction Printer	$5,844.84	4	42	$23,379.36	$245,483.28	$16,304.77	$170,070.82
Color Laser Multifunction Printer	$6,257.60	16	53	$100,121.66	$331,653.01	$69,824.85	$229,769.21
Color Laser Multifunction Printer	$7,158.25	68	18	$486,761.19	$128,848.55	$339,467.25	$89,266.28
Color Laser Multifunction Printer	$15,669.98	4	0	$62,679.92	$0.00	$43,712.98	$0.00
Software, labor, contractor and overhead and other costs				$79,257.43	$37,158.24	$55,274.13	$25,743.23
Total Electric Allocation				$927,226.76	$924,689.28	**$646,647.94**	**$640,624.73**

- The **ARP — Collaboration** project requires $422,302 in capital and $331,265 in O&M. This project will replace the Company's collaborative tools and equipment. This project creates value by: (1) ensuring that the Company's audio, visual, telephony, and other communications systems are stable and reliable; and (2) beginning the foundational retirement of the legacy Avaya

PBX systems that have reached end of mainstream manufacturer support. The project scope consists of: (1) annually replacing collaboration assets; and (2) installing new collaboration assets to account for organic growth requirements. The alternatives considered were to: (1) refresh visual assets and a portion of the audio assets; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only. These alternatives were not chosen due to the risk inherent with a partial replacement of assets which includes: (1) a reduced supply of equivalent replacement Avaya parts that are no longer being produced; and (2) an erosion of the knowledge technicians possess on discounted systems in favor of education on the newest available technology.

Following are the projected capital costs for ARP – Collaboration project attributable to the electric business for 2020 and 2021 test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Test Year Dollars	Electric Allocation Dollars
LED HDTV	$1,715.00	8	8	$13,720.00	$13,720.00	$7,825.89
Wireless Presentation System	$1,675.00	6	6	$10,050.00	$10,050.00	$5,732.52
Camera	$3,645.00	6	6	$21,870.00	$21,870.00	$12,474.65
Tabletop Conference System Video Package	$2,120.00	8	8	$16,960.00	$16,960.00	$9,673.98
Group Video Conferencing	$14,415.00	3	3	$43,245.00	$43,245.00	$24,666.95
Projection Screen	$1,458.15	8	8	$11,665.20	$11,665.20	$6,653.83
Professional Laser Projector	$6,475.00	8	8	$51,800.00	$51,800.00	$29,546.72
Package Server	$100,000.00	1	0	$100,000.00	$0.00	$0.00
Software, labor, contractor and overhead and other costs				$571,051.80	$571,051.80	$325,727.95
Total Electric Allocation				$840,362.00	$740,362.00	**$422,302.48**

Following are the actual and projected capital costs for ARP – Collaboration project attributable to the electric business for 2018 and 2019 in the table below.

Units	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Electric Allocation Dollars	2019 Electric Allocation Dollars
Wall Monitor	$24,292.99	10	0	$242,929.90	$0.00	$141,385.20	$0.00
Room Manager	$1,269.67	10	0	$12,696.70	$0.00	$7,389.48	$0.00
Video Conferencing	$11,659.58	8	0	$93,276.65	$0.00	$54,287.01	$0.00

Hardware Security Module	$354,754.39	1	0	$354,754.39	$0.00	$206,467.05	$0.00
Auditorium Systems	$124,065.33	2	0	$248,130.66	$0.00	$144,412.04	$0.00
IP Based Call Recording System	$156,015.81	1	0	$156,015.81	$0.00	$90,801.20	$0.00
Conference Room Projector Only System	$4,241.76	22	0	$93,318.72	$0.00	$54,311.50	$0.00
Audio System Server	$7,188.16	0	1	$0.00	$7,188.16	$0.00	$4,100.13
New Generation Wall Monitors	$14,625.00	0	5	$0.00	$73,125.00	$0.00	$41,710.50
EP2-135 Audio System	$62,573.39	0	1	$0.00	$62,573.39	$0.00	$35,691.86
Flint Audio	$9,400.00	0	1	$0.00	$9,400.00	$0.00	$5,361.76
UPS	$87,000.00	0	1	$0.00	$87,000.00	$0.00	$49,624.80
Flint HVAC	$43,000.00	0	1	$0.00	$43,000.00	$0.00	$24,527.20
Phone Manager system	$60,000.00	0	1	$0.00	$60,000.00	$0.00	$34,224.00
Hub stands	$736.52	0	8	$0.00	$5,892.16	$0.00	$3,360.89
Software, labor, contractor and overhead and other costs				$875,487.74	$247,260.19	$509,533.86	$141,037.21
Total Electric Allocation				$2,076,610.57	$595,438.90	**$1,208,587.35**	**$339,638.35**

- The **ARP — Wireless Network** project requires $2,037,772 in capital and $234,969 in O&M. This project will replace portions of the company's aging wireless systems. This project creates value for the Company by: (1) ensuring real-time communications between Company crews and dispatch locations; (2) ensuring efficient gas leak and electric outage response times for customers;

and (3) maintaining critical infrastructure and regulatory compliance. The project scope consists of: (1) replacing wireless assets annually; and (2) installing additional new wireless assets to account for organic growth requirements. The alternatives considered for system replacement were: (1) running parallel systems while the new system is deployed and the old system is dismantled; and (2) leasing a system from a vendor. The first alternative was not chosen since it would be highly disruptive due to systems having to run independently of one another and would have a high cost associated with the need to acquire additional radio frequency spectrum. The second alternative was not chosen since the Company would be dependent on the response times offered by a shared vendor system that offers lower system reliability. The Company chose to replace existing assets based on its refresh cycle to avoid extended support cost, and to provide a seamless transition that allows both the old and new systems to interact with little to no disruption to the end user.

Following are the projected capital costs for ARP – Wireless Network project attributable to the electric business for 2020 and 2021 test year in the table below.

Units	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Test YearDollars	Electric Allocation Dollars
Storage Boxes	$2,120.00	227	227	$481,240.00	$481,240.00	$274,499.30
Modem	$1,060.00	367	367	$389,020.00	$389,020.00	$221,897.01
800Mhz Mobile front mount	$3,174.00	300	300	$952,200.00	$952,200.00	$543,134.88
800Mhz Mobile remote mount	$3,174.00	58	58	$184,092.00	$184,092.00	$105,006.08
Conventional Radio (fixed site)	$8,191.00	11	11	$90,101.00	$90,101.00	$51,393.61
Conventional (low end subscriber)	$265.00	272	272	$72,080.00	$72,080.00	$41,114.43
Conventional (high end subscriber)	$1,060.00	240	240	$254,400.00	$254,400.00	$145,109.76
Dispatch Consoles	$30,917.00	12	12	$371,004.00	$371,004.00	$211,620.68
Cores	$636,000.00	1	1	$636,000.00	$636,000.00	$362,774.40
Site UPS Batteries	$1,060.00	11	11	$11,660.00	$11,660.00	$6,650.86
Software, labor, contractor and overhead and other costs				$130,353.00	$130,735.00	$74,571.24
Total Electric Allocation				$3,572,150.00	$3,572,532.00	**$2,037,772.25**

Following are the actual and projected capital costs for ARP – Wireless Network project attributable to the electric business for 2018 and 2019 in the table below.

Units	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Electric Allocation Dollars	2019 Electric Allocation Dollars
Storage Boxes	$1,626.95	150	200	$244,042.50	$325,390.00	$142,032.74	$185,602.46
Modem	$1,150.26	0	411	$0.00	$472,756.86	$0.00	$269,660.51
Modem	$636.69	125	0	$79,586.25	$0.00	$46,319.20	$0.00
Generator (Tawas)	$22,415.00	0	1	$0.00	$22,415.00	$0.00	$12,785.52
LED Flash Lighting system	$9,710.00	4	4	$38,840.00	$38,840.00	$22,604.88	$22,154.34
800Mhz Mobile front mount	$2,575.80	50	0	$128,790.00	$0.00	$74,955.78	$0.00
800Mhz Mobile front mount	$2,411.65	250	200	$602,912.50	$482,330.00	$350,895.08	$275,121.03
800Mhz Mobile remote mount	$2,486.77	200	200	$497,354.00	$497,354.00	$289,460.03	$283,690.72
800Mhz Portable Radios	$2,976.48	0	100	$0.00	$297,648.00	$0.00	$169,778.42
800Mhz Portable Radios	$2,410.12	0	75	$0.00	$180,759.00	$0.00	$103,104.93
Desktop microphones	$155.76	70	0	$10,903.20	$0.00	$6,345.66	$0.00
Radio keys	$111.68	107	40	$11,949.76	$4,467.20	$6,954.76	$2,548.09
VHF Antenna system	$5,887.64	0	1	$0.00	$5,887.64	$0.00	$3,358.31
Trunked radio equip	$15,884.74	0	1	$0.00	$15,884.74	$0.00	$9,060.66
Conventional Radio Repeaters	$5,880.03	0	3	$0.00	$17,640.09	$0.00	$10,061.91

JGS/GRY conventional systems	$9,862.77	0	2	$0.00	$19,725.54	$0.00	$11,251.45
800MHz Tower Ant	$12,562.74	1	0	$12,562.74	$0.00	$7,311.51	$0.00
Software, labor, contractor and overhead and other costs				$311,952.02	150,175.28	$181,556.08	$85,659.98
Total Electric Allocation				$1,938,892.97	$2,531,273.35	**$1,128,435.71**	**$1,443,838.32**

- The **ARP — Field Device Asset Management ("FDAM")** project requires $1,575,480 in capital and $7,888 in O&M. This project will replace field devices. This project creates value for the Company by: (1) mitigating potential costs for hardware repairs; and (2) allowing field workers to complete their job tasks. The project scope consists of replacing field device assets. The alternatives considered were to: (1) extend refresh cycles from four years to five years; and (2) run the assets to failure. The selection of a four-year cycle was deemed to be the best solution because replacement in less than four years would result in additional unnecessary expense for replacement of assets that are still in peak operating condition and replacement cycles that exceed four years, including running the asset to failure, would result in additional expenses in maintenance of the equipment and downtime, which negatively impact employee productivity.

  Following are the projected capital costs for ARP – FDAM project attributable to the electric business for 2020 and 2021 test year in the table below.

Units	**Avg. Unit Cost**	**Total 2020 Units**	**Total 2021 Units**	**Total 2020 Dollars**	**Total 2021 Test Year Dollars**	**Test Year Electric Allocation Dollars**
Field Devices	$3,969.70	454	459	$1,802,243.80	$1,822,092.30	$1,262,345.55
LeakCon Devices	$3,969.70	0	100	$0.00	$396,970.00	$275,020.82
Software, labor, contractor and overhead and other costs				$54,126.20	$55,013.70	$38,113.49
Total Electric Allocation				$1,856,370.00	$2,274,076.00	**$1,575,479.85**

Following are the actual and projected capital costs for ARP – FDAM project attributable to the electric business for 2018 and 2019 in the table below.

Units	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total Actual 2018 Dollars	Total Projected 2019 Dollars	2018 Electric Allocation Dollars	2019 Electric Allocation Dollars
Field Devices G1s & Accessories	$3,969.70	406	440	$1,611,698.20	$1,746,668.00	$1,123,998.32	$1,210,091.59
Meter Reading	$4,452.00	35	48	$155,820.00	$213,696.00	$108,668.87	$148,048.59
Software, labor, contractor and overhead. and other costs				$10,147.26	38.79	$7,076.70	$26.87
Total Electric Allocation				$1,777,665.46	$1,960,402.79	**$1,239,743.89**	**$1,358,167.05**

- The **ARP — Workstation Asset Management ("WAM")** project requires $5,107,804 in capital and $86,724 in O&M. This project will replace and install new desktops, laptops, and tablets. This project creates value for the Company by: (1) improving stability and availability of business critical applications by proactively replacing workstations prior to the chance of hardware failures increasing; and (2) allowing business partners to complete their job tasks. The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources. The alternatives considered were to: (1) extend the replacement cycle from four years to five years for all desktops and laptops; (2) extend the replacement cycle only on desktops from four years to five years; and (3) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the ARP by $4 million in future years; and (4) it could cause an inability to apply security patches. The Company selected a four-year refresh cycle to alleviate these concerns.

Following are the projected capital costs for ARP – WAM project attributable to the electric business for 2020 and 2021 test year in the table below.

Units	**Avg. Unit Cost**	**Total 2020 Units**	**Total 2021 Units**	**Total 2020 Dollars**	**Total 2021 Test Year Dollars**	**Electric Allocation Dollars**
Replacements						
Desktops	$922.20	984	563	$907,444.80	$519,198.60	$359,700.79
Laptop	$2,144.38	2,200	1,400	$4,717,636.00	$3,002,132.00	$2,079,877.05
Rugged Devices	$3,914.58	8	4	$31,316.64	$15,658.32	$10,848.08
Monitors	$265.00	4,109	3,925	$1,088,885.00	$1,040,125.00	$720,598.60
New Purchases						
Laptops	$2,144.38	520	520	$1,115,077.60	$1,115,077.60	$772,525.76
Rugged Devices (Semi Rugged devices)	$3,657.35	201	201	$735,127.49	$735,127.49	$509,296.33
Desktop Bundled	$922.20	20	20	$18,444.00	$18,444.00	$12,778.00
Desktop Bundled	$2,544.00	10	10	$25,440.00	$25,440.00	$17,624.83
Desktop	$752.60	20	20	$15,052.00	$15,052.00	$10,428.03
Tablets	$1,500.28	18	18	$27,005.07	$27,005.07	$18,709.11
Monitors	$265.00	1,578	1,578	$418,170.00	$418,170.00	$289,708.18
Accessories				$145,683.00	$145,683.00	$100,929.18
Software, labor, contractor and overhead and other costs				$441,200.40	$295,582.92	$204,779.85
Total Electric Allocation				$9,686,482.00	$7,372,696.00	**$5,107,803.79**

Following are the actual and projected capital costs for ARP – WAM project attributable to the electric business for 2018 and 2019 in the table below.

Units	**Avg. Unit Cost**	**Total 2018 Units**	**Total 2019 Units**	**Total 2018 Dollars**	**Total 2019 Dollars**	**2018 Electric Allocation Dollars**	**2019 Electric Allocation Dollars**
Replacements							
Desktops	$795.00	713	700	$566,835.00	$556,500.00	$395,310.73	$385,543.20
Desktop Bundled	$2,696.64	36	0	$97,079.04	$0.00	$67,702.92	$0.00
Laptop	$1,800.94	1,744	850	$3,140,839.36	$1,530,799.00	$2,190,421.37	$1,060,537.55
Desktop bundled	$4,282.40	96	0	$411,110.40	$0.00	$286,708.39	$0.00
Rugged Devices	$3,914.58	13	15	$50,889.54	$58,718.70	$35,490.37	$40,680.32

Monitors	$265.00	3,598	2,300	$953,470.00	$609,500.00	$664,949.98	$422,261.60
New Purchases							
Laptops	$1,800.94	536	316	$965,303.84	$569,097.04	$673,202.90	$394,270.43
Desktop bundled	$4,282.40	81	0	$346,874.40	$0.00	$241,910.21	$0.00
Rugged Devices (Semi Rugged devices)	$3,096.26	40	25	$123,850.40	$77,406.50	$86,373.27	$53,627.22
Desktop Bundled	$795.00	56	30	$44,520.00	$23,850.00	$31,048.25	$16,523.28
Desktop Bundled	$2,544.00	1	4	$2,544.00	$10,176.00	$1,774.19	$7,049.93
Tablets	$1,418.99	9	25	$12,770.88	$35,474.67	$8,906.41	$24,576.85
Monitors	$265.00	332	313	$87,980.00	$82,945.00	$61,357.25	$57,464.30
Curved Monitors	$1,007.00	365	0	$367,555.00	$0.00	$256,332.86	$0.00
Accessories				$151,653.77	$145,000.00	$105,763.34	$100,456.00
Software, labor, contractor and overhead and other costs				$249,467.21	$333,430.71	$173,978.43	$231,000.80
Total Electric Allocation				$7,572,742.84	$4,032,897.62	**$5,281,230.86**	**$2,793,991.47**

- The **ARP — Server and Storage** project requires $8,550,238 in capital and $411,177 in O&M. This project will replace or augment server and storage infrastructure for the Company. This project creates value for the Company through: (1) improved stability and availability of business critical applications by proactively replacing server and storage hardware assets prior to the chance of hardware failures increasing; and (2) ensuring that adequate resources are available to support application demands after five to seven years of actual use. The scope of this project encompasses: (1) replacement of server and storage hardware assets; and (2) installation of additional new computers and storage capacity to account for organic growth requirements. The alternative considered was to purchase extended maintenance. This solution was not selected because full support would not be offered after seven years and maintenance costs would increase. The Company continues to refresh these critical technologies based on a five- to seven-year refresh cycle to mitigate the risk of failure.

Following are the projected capital costs for ARP – Server and Storage project attributable to the electric business for 2020 and 2021 test year in the table below.

Units*	Avg. Unit Cost	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Test Year Dollars	Electric Allocation Dollars
HyperConverged Appliance	$127,200.00	25	25	$3,180,000.00	$3,180,000.00	$2,203,104.00
HyperConverged Appliance	$169,600.00	25	25	$4,240,000.00	$4,240,000.00	$2,937,472.00
Server Blades (Full)	$87,375.00	8	0	$699,000.00	$0.00	$0.00
Data Protection Software	$185,500.00	0	1	$0.00	$185,500.00	$128,514.40
Data Domain	$1,590,000.00	0	2	$0.00	$3,180,000.00	$2,203,104.00
Labor, contractor and overhead and other costs				$1,151,999.00	$1,556,068.00	$1,078,043.91
Total Electric Allocation				$9,270,999.00	$12,341,568.00	**$8,550,238.31**

*Units includes hardware and software costs.

Following are the actual and projected capital costs for ARP – Server and Storage project attributable to the electric business for 2018 and 2019 in the table below.

Units*	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Electric Allocation Dollars	2019 Electric Allocation Dollars
Server Blades (Half)	$43,562.82	0	2	$0.00	$87,125.64	$0.00	$49,696.47
Hyperconverged Appliance	$102,854.71	0	10	$0.00	$1,028,547.09	$0.00	$586,683.26
Server Rack	$11,968.00	2	0	$23,936.00	$0.00	$16,692.97	$0.00
Backup Software	$146,327.34	1	0	$146,327.34	$0.00	$102,048.69	$0.00
Data Domain	$927,233.44	2	0	$1,854,466.87	$0.00	$1,293,305.20	$0.00
Server Blade	$54,151.68	28	4	$1,516,247.07	$216,606.72	$1,057,430.71	$123,552.48
Stand Alone Site Server	$6,591.26	12	6	$79,095.12	$39,547.56	$55,160.94	$22,557.93
Storage Array	$357,690.48	2	0	$715,380.95	$0.00	$498,906.67	$0.00
Data Domain Shelf	$254,539.63	0	3	$0.00	$763,618.88	$0.00	$435,568.21

Hardware Shelf	$349,673.02	3	0	$1,049,019.05	$0.00	$731,585.89	$0.00
Network Card	$8,256.43	1	0	$8,256.43	$0.00	$5,758.03	$0.00
Software	$3,252.52	16	0	$52,040.32	$0.00	$36,292.92	$0.00
Network	$43,550.96	0	2	$0.00	$87,101.92	$0.00	$49,682.94
Labor, contractor and overhead, and other costs				$437,532.45	$699,661.10	$305,135.13	$399,086.69
Total Electric Allocation				$5,882,301.60	$2,922,208.91	**$4,102,317.14**	**$1,666,827.96**

*Units includes hardware and software costs.

Q. Please explain Upgrades and Application Currency projects.

A. The following are the Upgrades and Application Currency projects:

- The **4G SAP Implementation** project requires $87,450 in O&M. There are approximately 680,000 smart meters in the Company's electric system that utilize the 3G wireless technology. The wireless carrier will be retiring the 3G network technology on December 31, 2022, requiring the Company to replace the 3G meters with 4G meters in order for them to continue functioning. This project will create the technology that enables Itron to upgrade smart meter communication modules from 3G to 4G technology. This project will add value by continuing the ability to: (1) communicate with the smart meters; (2) provide accurate and timely bills to customers; (3) execute remote turn-ons and turn-offs; (4) receive outage information; and (5) administer demand response events. The project scope includes: (1) building technology interfaces to meter installation vendor technology; which include an interface to extract list of 3G meter information; an interface for posting work order completion data in SAP, and an interface for tracking exceptions and errors; and (2) end-to-end testing of the interfaces and back-end technology (meter-to-cash processes). The alternatives considered were: (1) migrating to a new meter platform; and (2) not implementing 4G technology in 3G meters. The first option would require a substantially larger modification to all supporting systems and infrastructure. The second option is not feasible since the depreciating communications technology will eventually make the meters non-communcative. The option of implementing 4G technology was chosen so the Company can continue to reap the benefits of the smart meter technology previously implemented. These benefits include: (1) improved timeliness and billing accuracy; (2) retaining ability for remote disconnect and reconnect of services; (3) administration of demand response programs; and (4) enabling automated meter reads, outage reporting, and faster restoration.

- The **Consumers Affordable Resource for Energy ("CARE") Annual Updates** project requires $207,574 in O&M. This project will: (1) implement software changes to improve the process for offering energy assistance to low-income customers; and (2) streamline the process for assistance agencies who utilize the application though improved user interface and updates to SAP to process various CARE requests. Upcoming modifications will be identified following an annual review of requests to prioritize the list of changes. The project will provide the following value: (1) complete modifications to the existing internal SAP application and Agency Portal to receive annual Low Income Home Energy Assistance Program ("LIHEAP") funding, which is used to provide customers bill credits and arrears forgiveness; and (2) improve the data within the assistance Agency Portal, thereby making it easier to assist customers in need of LIHEAP funding. The project scope includes: (1) updating the enrollment and status process; (2) allowing for flexible bill credits; (3) improving reporting; (4) updating the arrears forgiveness plan; and (5) satisfying additional regulatory requirements for the annual grant rule changes required by the Michigan Department of Health and Human Services and the Michigan Agency for Energy. The alternative considered was to continue with the current process. This alternative was not chosen since it would result in loss of grant funding, thus decreasing or eliminating energy assistance dollars for low income customers. Instead, making annual updates to the application will allow agencies to easily enroll customers on assistance programs, and allow placement of holds to stop or prolong credit activity until assistance decisions are granted. This option provides long-term proactive energy assistance to low income customers and prevents loss of grant funds. All changes are related to the existing internal SAP and Agency Portal; therefore, a cloud alternative is not viable.

- The **Enterprise Service Bus ("ESB") Application Upgrade** project requires $497,780 in capital and $975,645 in O&M. This project will upgrade and migrate the Business Works developer application to the next version. The value this project provides the Company includes: (1) accelerated productivity; (2) continuous delivery and integration; (3) an open ecosystem for improved operational visibility; (4) real-time integration with web, mobile apps, and application programming interfaces; and (5) improved administrative and operational efficiencies. The upgrade will also provide for easy integration with other coud-based solutions such as Amazon Web Services and easy migration to cloud-based containers in the future. The project scope includes: (1) implementing new versions of all applications that are part of the ESB in two security zones; and (2) a server refresh. The new products will be implemented on the latest version of the SUSE Enterprise Edition operating system. The alternative considered was to absorb the annual $40,000 maintenance cost and lose supportability. Given the critical nature of this application, it is not recommended to lose mainstream support for any of the applications involved. Any sustained ESB product deficiency would impact many areas of the company such as billing, revenue collection, and remote meters. This alternative was not chosen due to these reasons, and the additional expense.

- The **Electronic Shift Operations Management System ("eSOMS") Upgrade** project requires $34,640 in capital and $214,674 in O&M. This project will perform a major upgrade of the eSOMS application, including servers. This project will completely rewrite the clearance and narrative logs and the safety critical emailer functionality to enable compatibility with the new version. The project will add value by: (1) reducing the human struggle with manual workarounds and old applications; (2) empowering employees with proper electronic tools to meet customer expectations; (3) enabling process improvements to deliver outages more effectively; (4) reducing plant downtime; and (5) increasing reliability. The scope of this project includes: (1) assessing any new functionality for value to the Company; (2) replacing the servers and upgrading the application software; (3) making necessary configuration changes; (4) testing any integrations to or from the application; (5) testing the upgrade; and (6) updating documentation related to the integration changes. Alternatives considered include: (1) continuing to use the application without vendor support at the risk of a critical application issue that results in an employee safety incident, extended plant production outage, prolonged plant reliability issue, or regulatory or compliance violation; (2) instituting the manual business continuity process until the application upgrade is possible, which would increase the previously mentioned business risks; or (3) revisiting the decision to utilize eSOMS and replace the application by customizing SAP. The option to upgrade the existing eSOMS application was chosen to minimize cost and risk to the Company and its employees.

- The **Time Entry and Expense Reports - Flash Remediation** project requires \$19,800 in O&M. This project will replace Adobe Flash with HTML 5 technology. Time entry and approvals and expense report approvals currently leverage Adobe Flash technology. By the end of 2020, Microsoft will remove the ability to run Adobe Flash in Microsoft Internet Explorer. The value of the project includes: (1) reducing security vulnerabilities that exist in Adobe Flash; (2) ensuring employees and managers can enter and approve time so employees are paid on time; and (3) ensuring managers can approve expense requests for reimbursement. The scope of the project includes: (1) replacing Adobe Flash technology with HTML 5; and (2) eliminating security risks associated with Adobe Flash. Alternatives considered for this project were to: (1) use SAP Fiori technology that provides mobile capabilities and reduces license and support costs with the external vendor; and (2) implement other software applications such as Concur. The first alternative would reduce functionality and impose a major training impact on more than 8,000 employees. The second alternative would require: (1) integration with SAP; (2) retraining of all employees; (3) additional licensing and support costs; and (4) custom development of rules and redevelopment of enhancements. The option to replace the current Adobe Flash solution with HTML 5 technology was selected because it is the least costly option with little to no impact to the Company's employees. This solution does not require retraining or the development of new custom time entry rules or enhancements.

- The **Human Resources ("HR") Support Pack and Business Software Inc. Upgrade** project requires \$680,942 in O&M. This project will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes. This project creates value for the Company by: (1) ensuring that it is in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll. The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company. As this is an upgrade of an existing system, the alternative considered was to delay the upgrade. This alternative was not chosen due to the risk of not complying with financial rules and regulations.

- The **ISIS Papyrus Upgrade** project requires $144,227 in O&M. 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. The value of this project includes: (1) providing a more stable operational model by upgrading to the most recent version available; and (2) resolving tuning and stability issues with the vendor. The scope of the project is to upgrade the various licensed products that comprise the Papyrus Objects suite of applications. As this is an upgrade of an existing system, the alternative considered was to delay the upgrade and continue operating with the current version. This alternative was not chosen due to the risk of application stability and the inability to maintain cyber security patching.

- The **Role Based Access Control** project requires $200,017 in O&M. This project will develop business roles based on job functions for the SAP environment. The value of completing the project is: (1) more efficient access control policy maintenance and certification; (2) more efficient provisioning by network and systems administrators; (3) reduced new employee downtime from more efficient provisioning; (4) enhanced organizational productivity; and (5) enhanced system security and integrity. The scope of this project includes the following systems: (1) SAP Enterprise Resource Planning ("ERP") Central Component; (2) Customer Relationship Management; (3) Business Warehouse; (4) Governance Risk and Compliance; (5) Solution Manager; (6) Process Orchestration; and (7) NetWeaver Development Infrastructure. As part of the review process, the alternative considered was to continue with access provisioning based on selection of specific functions and processing multiple approvals. However, this alternative was not selected because it does not eliminate waste in the form of human struggle, rework, and extra processing. The alternative to implement role-based access control was selected because of the financial savings and process improvements.

- The **S/4HANA Assessment** project requires $118,800 in O&M. This project will review options for moving to the new platform before the current SAP platform is no longer supported, which is currently projected to occur in 2024. The value of the project is to: (1) devise the best option to migrate to a new platform at the least cost; (2) ensure that the Company is prepared to move to the new platform by projected 2024 end of SAP support; and (3) ensure that all alternatives have been explored so that the best option is implemented. The scope of the project includes: (1) reviewing SAP options for migrating to a new platform; (2) reviewing alternative platform options that the Company could utilize in place of S/4HANA; (3) reviewing support options for the existing SAP platform past 2024; and (4) providing cost and alternative options so the Company can develop a project for the best option to address the SAP platform. Three alternatives were explored and determined non-viable for the project: (1) completing the assessment as the initial phase of the implementation project would limit the amount of options considered and make assumptions about cost needed to stand up the project; (2) delaying the assessment until a later date would not give the Company enough time to prepare for the implementation; and (3) completing an assessment that had a scope limited only to migrating to the new SAP platform may result in the Company accepting a sub-optimal solution. The option selected gave the Company the best opportunity to look at all viable options and to have enough lead time for transition to the new database.

- The **SAP Access Controls** project requires $109,809 in capital and $250,800 in O&M. This project replaces the current software tool that manages and monitors Sarbanes-Oxley Act ("SOX") compliance for SAP transactions. The project will add value by: (1) reducing risk and eliminating waste through new tools that provide higher levels of automation and process optimization; (2) decreasing maintenance and upgrade costs by implementing the out-of-the-box solution without customization; (3) increasing the ability to meet requirement changes from auditors and the Public Company Accounting Oversight Board; and (4) creating complete and accurate report capabilities. The project scope includes: (1) automating the SAP periodic user access review; (2) automating the emergency access management process; (3) displaying areas of risk and identifying how to mediate that risk; (4) tracking mitigations; and (5) converting the current rule set into the new tool. The alternatives that were considered and deemed to be non-viable are: (1) continue using the current application as-is, accepting the audit risks stemming from the known issues and the risk associated with standard SAP support ending on December 31, 2020, and continue following current error-prone manual processes; (2) use robotic process automation in a limited scope to automate some manual tasks and reduce errors, which due to limited functionality would not mitigage risks and gaps in the current tool; (3) develop a custom solution to perform some of the work, which would is expected to be more costly and include higher maintenance and support costs; and (4) continue to apply program patches and fixes from SAP to the current tool, which may not address or fulfill all requirements, and requires support from an external vendor, which increases support costs. The option to replace the existing tool with a new solution: (1) meets Company requirements; (2) avoids hiring two additional resources; (3) is more cost effective in the long term; (4) adds more process automation; and (5) increases SOX compliance.

- The **SAP Data Archiving** project requires $380,001 in capital and $171,270 in O&M. This project will move outdated data from an online database to offline storage. This project will create value for the Company by: (1) increasing system stability by reducing data growth; and (2) controlling maintenance costs associated with data storage. The project scope includes: (1) archiving data based on the fastest growing and largest objects in SAP; (2) building and archiving solutions that allow the business to retrieve archived data in the required form; and (3) setting up the solution so that the business areas meet compliance standards. Three alternatives were explored and determined non-viable for the project: (1) allow the database to grow in size, which would put system performance at risk and result in prohibitive storage costs; (2) decrease the overall scope and archive fewer projects, which would result in minimal positive impact to system growth and significant storage-related costs; and (3) increase the scope and archive more objects in a shorter timeframe, which would result in a significant cost increase over shorter time period. After considering each of these options, it was determined that the current scope of the project was the best strategy to address the problem while balancing annual spending.

- The **SAP Data Encryption** project requires $838,035 in O&M. This project will implement Information Security standards for encryption of Personally Identifiable Information ("PII"). These standards include SAP data in various states: (1) at rest; (2) in use; and (3) in transit. This project creates value for the Company and its customers by: (1) reducing the risk of compromise of customers' personal information and the resulting impact to the Company's reputation; (2) ensuring compliance with Information Security standards for encryption for SAP data at rest and in transit; (3) reducing the Company's liability due to personal data breaches; and (4) ensuring compliance with future federal legislation that may make this mandatory. The scope of this project includes: (1) data encryption for data at rest, in use, and in transit; and (2) applies to all SAP PII collected, used, retained, disclosed, and disposed of by the Company. Such information includes the PII of customers, employees, contractors, directors, and shareholders. As part of the review process the alternative considered was to accept all risks as outlined above and not implement the data encryption standards. However, this was not considered a viable activity since accepting the risk could compromise customers' personal information and does not align with current internal Information Security standards. Additionally, there is pending federal legislation that may mandate this work.

- The **Service Suite Upgrade** project requires $1,446,068 in capital and $1,243,726 in O&M. This project will: (1) implement a new version of Service Suite Work Management that allows for easier distribution to the field; and (2) maintain a current version on a vendor supported platform for this critical enterprise application used across Operations and Engineering. The product enhancements in Service Suite and TC Technology's Mobile Information Management System ("MIMS") will be implemented to provide additional business value and benefits. The project will add value by: (1) implementing a new version that provides the highest level of vendor support for this 24x7 critical system that serves over 100,000 work orders weekly; (2) implementing Service Suite Fieldworker Mobile for a touch-based interface and migration to cloud-based configurations; (3) providing live traffic display on Dispatch Application; and (4) improving readability and usability of Dispatch Application schedule view. The scope of the project includes: (1) implementing the new version of Service Suite Work Management; and (2) implementing MIMS for mobile mapping on the field device to improve safety, response, usability, and supportability of the critical application. The alternatives considered and determined not to be viable included: (1) remaining on the current Service Suite version, which would cause continuation of additional manual steps in the emergency response and work assignment; or (2) creating a custom-developed solution, which would increase waste and inefficiency without the same level of Service Suite integration. Upgrading Service Suite was chosen because it allows the Company to stay on the current and supported version of the application already being used and also adds functionality that will provide additional business value and benefits.

- The **Sitecore Upgrade** project requires $545,302 in O&M. This project will refresh all components of the website hosting, delivery, search, and analytics applications to add new features and improve search capabilities. Sitecore is the content manager for the ConsumersEnergy.com website. The project will add value by providing these four benefits: (1) maintains currency with the web hosting application version; (2) allows business users to make use of new features and functionality; (3) neutralizes continually evolving cyber threats; and (4) continuously improves customer experience using ConsumersEnergy.com. The project scope includes: (1) upgrading the Sitecore content management software to include content hosting and delivery allowing the use of new features and functionality; (2) upgrading the Coveo software, which will allow for more intuitive search results and provide suggestions or recommendations based on the customers' search text; (3) upgrading the Mongo database, which provides the analytics functionality within Sitecore to better understand customer actions and errors on the web page; and (4) developing analytics across customers' web and contact center interactions, allowing the company to connect contact center call data with corresponding web data for improved customer experience. Alternatives considered but deemed not to be viable include: (1) implementing a two-year upgrade cycle, which would not position the Company to be able to keep up with constantly changing cyber threats, or gain value from the rapidly changing feature set being developed by the vendor; and (2) purchasing an existing cloud solution, which is cost prohibitive at this time. Annually upgrading the existing Sitecore platform provides the functionality and stability needed while meeting financial requirements and mitigating cyber security risks.

- The **Software Platform Refresh** project requires $451,398 in O&M. This project will upgrade server operating systems, hypervisors (virtual machine monitors), and databases to retain low-cost, unlimited vendor support. These platforms support all the Company's applications including critical company and customer applications. The project will add value for the Company by: (1) avoiding costs for special maintenance agreements required at the end of normal manufacturer support; (2) ensuring reliability and compliance with Information Security requirements; (3) improving data center environment stability; and (4) avoiding the need for high risk upgrades that cross multiple versions. The project scope includes: (1) upgrading operating systems and databases on servers that are within three years of end of support; and (2) maintaining hypervisors at the current version for stability and performance. A funding options matrix was completed to review the alternatives. The options were: (1) fund the full project for $1 million and pay no support liability in 2020; (2) fund $750,000 of the project and pay $1.6 million in support liability in 2020; (3) fund $500,000 of the project and pay $2.4 million in support liability in 2020; and (4) not funding the project and pay $3.3 million for support liability in 2020. Alternative options 2–4 were not selected due to the high cost of support liability. Option 1 was chosen to avert these costs and to ensure system stability.

- The **Itron Enterprise Edition ("IEE") Upgrade** project requires $381,040 in capital and $551,430 in O&M. This project will upgrade IEE, which collects the reads from meters to ensure accurate and non-estimated bills are provided to our customers. This project creates value for the Company by: (1) ensuring the new features and functionality added to meet business requirements are available to business partners and IT; (2) meeting Information Security's requirement to keep applications patched to control cyber debt; and (3) allowing for validation, estimation, and editing functions for all data collected. The scope of this project includes: (1) an operating system refresh; (2) migrating from Windows 2012 to the next Windows version; and (3) migrating the database from SQL Server version 2012 to the next SQL Server version. As this is an upgrade of an existing system the alternative considered was to delay the upgrade. This alternative upgrade was not chosen due to the risk to the stability and cyber security of the system.

- The **SAP Optimization and Tuning** project requires $231,919 in O&M. This project will maintain and improve the operation of the SAP system by addressing data issues within the system, optimizing database structures, and fixing sub-optimal code. The project creates value by improving the performance of the SAP system, which improves the customer's online self-service experience and allows employees serving the customer to complete timely transactions. The project scope includes: (1) normalizing multiple accounts assigned to a single business partner; (2) purging duplicate or unnecessary records; (3) purging unneeded technical data; (4) reviewing and optimizing custom code; and (5) implementing minor service pack updates provided by the vendor. The alternative considered was breaking the scope into individual work efforts to be individually completed. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work effort. The selected project scope was determined to be the best balance of maintaining overall SAP performance and optimizing cost.

- The **Electric High Voltage Distribution Monitoring System Upgrade** project requires \$142,000 in capital and \$5,000 in O&M. This project upgrades the software components of the HVD SCADA system, which is used to monitor and control generation, transmission, and high voltage distribution voltage circuits. The upgrade will provide new functionality and enable new capabilities. Upgrading the HVD SCADA software adds value to the Company by ensuring that problems are promptly addressed when they occur. Additionally, the upgrades include enhancements and fixes to the core product that support reliability of electric delivery, ensuring that customers are receiving the energy they need when they need it. Also, because the reliability of the re-distribution system is dependent upon availability of the HVD system, staying current with the solution provider upgrades is critical to the reliability of the distribution system. The scope of this project is an upgrade to the HVD SCADA software which encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; and (4) updating documentation related to the integration changes. The alternative considered was to defer the biennial upgrade of the SCADA application. 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 need for vendor support of the application.

- The **SQL ("SQL") Server Database Upgrade** project requires \$317,081 in capital and \$701,019 in O&M. This project, which supports critical applications such as the meter read collection systems and the customer contact center applications, will upgrade all SQL Server 2000–2014 instances to the latest version. This project will create value for the Company and its customers by: (1) reducing the risk of system failure and the resulting impacts to business partners and customers; and (2) ensuring that systems are secure, supported, and have the latest features and functionality. Project scope includes: (1) upgrades to all SQL Server 2000–2014 instances currently in use and not identified as part of another portfolio upgrade project, legal hold, or pending system retirement (approximately 400 instances); (2) installation and/or distribution of new SQL Server Client Tool software packages to affected workstations and application servers; (3) new Nimbus virtual machine templates for the new SQL Server release; and (4) technical database support to IT portfolios, business partners, and vendors during all project phases. The alternative considered was to migrate to Azure Cloud. As part of this option, the organization would obtain three years of extended support through Microsoft on SQL Server versions 2005–2008. This option was not selected because extended support would not be provided 2012 and 2014 versions, and the organization would not reap the benefits of new features offered through the upgrade. The Company decided in favor of the upgrade to avoid these issues and ensure system stability.

- The **Oracle Server Database Upgrade** project requires \$63,832 in capital and \$450,965 in O&M. This project will upgrade Oracle server databases to the next version and supportability across business portfolios. This project will create value for the Company and its customers by: (1) reducing the risk of system failure and the resulting impacts to business partners and customers; and (2) ensuring that systems are secure, supported, and have the latest features and functionality. The scope of this project includes upgrading to the next version of Oracle across all business systems. As this is an upgrade of an existing system the alternative considered was to delay the upgrade. This alternative upgrade was not chosen due to the risk to the stability and supportability of the system.

- The **800 MHZ Modernization** project requires \$5,091,390 in capital. This project will replace antiquated headend (the main audio routing switch for tower sites and dispatch consoles), tower site, dispatch, and radio infrastructure, as well as user-subscribed equipment with infrastructure that meets current Project 25 ("P25") standards. P25 standards are for digital mobile radio communications that are used by North American public safety and dispatch organizations. The current equipment was implemented in 1994 and is no longer manufactured or sold, so the Company is unable to find replacement parts. This project creates value for the Company by: (1) moving the Company to current production equipment that can be replaced and is more stable; (2) enabling the organization to migrate from an unsupported to a supported platform; (3) allowing for quicker response to electric outages; and (4) increasing customer and employee safety. The scope of the project includes: (1) the design; (2) configuration; and (3) implementation of P25 systems for headends, tower sites, dispatch consoles, and subscriber equipment. The alternatives considered were to: (1) remain with the current system; and (2) forklift the migration to other manufacturers and architecture. Option 1 was not selected because the equipment is not supported, and the organization is unable to find replacement parts. Option 2 was not chosen because there would be a larger learning curve, it would be more disruptive to business, and it would require a complete replacement of the existing system. The Company chose to go with the upgrade because it has been incrementally adopting the P25 standards through the wireless ARP, and this prudently utilizes current and ongoing investments. The upgrade is the easiest and least disruptive path to migrate to the P25 standards.

- The **Enhancements - Cloud Automation** project requires \$542,769 in capital and \$117,986 in O&M. The Company's existing cloud automation platform consists of a number of scripts that automate the build of infrastructure like servers, operating systems, databases, and application installations in minutes or hours. These scripts include security hardening and application of the latest patches. This project will maintain and improve these scripts to ensure they meet the latest security policy and requirements and any changes to the way the operating systems, databases, or applications are configured. The value of this project is inherent in the time savings and quality improvement, as it used to take weeks or even months to manually build infrastructure servers, which is prone to human error. The scope includes updating and improving the cloud automation platform to align with the Company's current security, database, operating system, network, and other application standards. The alternative would be to continue as is with existing scripts; however, this introduces security risks and additional manual steps to build infrastructure, which will lead to increased costs and risk of manual errors.

- The **Electric Geographic Information System (GIS) Platform Upgrade** project requires $768,000 in capital and $312,125 in O&M. This project will upgrade the GIS platform applications, servers, application hosting servers, and databases to the next major versions to remediate the outdated platform technology. The project adds value by: (1) remediating GIS, Windows, and Citrix technology obsolescence, creating a stable and sustainable foundational platform for critical business functions; (2) improving platform resilience by remediating current single-point-of-failure areas; (3) sharing technology resources (servers, databases, etc.) across gas and electric platforms to optimize them, yet still ensuring the ability to meet diverse business area functional needs; and (4) adding new capabilities for spatial analytics, real-time visualization of data, and three-dimensional infrastructure network traceability. In addition, the GIS platform remediation work establishes the foundation necessary for the full implementation of the Electric Distribution Asset Management Program. Project scope includes: (1) building GIS platform servers, software, and data; (2) expanding GIS platform capabilities; (3) re-architecting current single-point-of-failure areas; (4) designing and developing new architecture; (5) upgrading database technology; (6) re-platforming the application hosting platform (Citrix); and (7) upgrading and reconfiguring applications that utilize the GIS platform. The alternatives considered for the project were to: (1) delay implementation, pay a premium for extended Windows support, and incur cyber security and business continuity risk for the application hosting platform and the GIS platform; (2) upgrade the platform to the Utility Network as a "big bang" approach without the incremental GIS version upgrade; and (3) perform an iterative platform upgrade to the next GIS version with application platform hosting upgrade, server replacements, and database upgrade, and shift the Utility Network upgrade to a future year. Option 1 was not selected since further project delays will prolong the security and business continuity risk, as well as increase the probability of risk impact due to the level of effort required to complete the project. Option 2 was not selected because the Utility Network upgrade effort is a transformational technology project, requiring extensive data migration in addition to the scope outlined in this project. Furthermore, this alternative will also incur security and business continuity risk given the complexity of a prolonged planning and design effort. Option 3 was selected to implement an iterative upgrade approach as it decreases the overall project complexity while mitigating aging technology platforms, which enables the future upgrade to the Utility Network in addition to addressing overall platform stability and sustainability in a timelier manner.

- The **Application Currency and Enhancements - Infrastructure Applications and Operations ("IAO") – O&M** project requires $214,821 in O&M in the test year. This project will apply O&M funding to keep applications current for security and reliability to make enhancements to existing software, and to address requests generated by changing business requirements. The project will also upgrade applications that support the IAO Portfolio. The value of regular upgrades to applications in the IAO Portfolio lies in: (1) enhancing security protections; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the IAO Portfolio. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for the IAO Portfolio. Prior to implementing the applications, a review is completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements are considered. This project makes ongoing upgrades and support for the applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks.

- The **Application Currency and Enhancements - Operational Technology - Capital** project requires $17,320 in capital and $19,436 in O&M in the test year. This project will utilize both capital and O&M funding to keep applications current for security and reliability, to make enhancements to existing software, and to address requests generated by changing business requirements. O&M is included in this project to complete the preliminary planning phase for capital enhancements and upgrades. The project will also upgrade the various applications that support the OT Portfolio. The value of regular upgrades to applications in the OT Portfolio lies in: (1) enhancing security protections; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for OT. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for OT. Prior to implementing the applications, a review is completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements are considered. This project makes ongoing upgrades and support for the applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes and to meet legally required system changes. Timing for an application upgrade is based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks.

- The **Application Currency and Enhancements – Transmission, Engineering, and Operational Support** (**"TEOS") - O&M** project requires $186,196 in O&M in the test year. This project will apply O&M funding to keep applications current for security and reliability, to make enhancements to existing software, and to address requests generated by changing business requirements. The project will also upgrade applications that support the TEOS Portfolio. The value of regular upgrades to applications in the TEOS Portfolio lies in: (1) enhancing security protections; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the TEOS Portfolio. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for areas supported by the TEOS Portfolio. Prior to implementing the applications, a review is completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements are considered. This project makes ongoing upgrades and support for the applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks.

- The **Application Currency and Enhancements - Operations - O&M** project requires $170,438 in O&M in the test year. This project will apply O&M funding to keep applications current for security and reliability, to make enhancements to existing software, and to address requests generated by changing business requirements. The project will also upgrade applications that support the Operations Portfolio. The value of regular upgrades to applications in the Operations Portfolio lies in: (1) enhancing security protections; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Operations. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for the Operations Portfolio. Prior to implementing the applications, a review is completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements are considered. This project makes ongoing upgrades and support for the applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Timing for an application upgrade is based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks.

- The **Application Currency and Enhancements – Customer Experience and Operations ("CE&O") - O&M** project requires $21,780 in O&M in the test year. This project will apply O&M funding to keep applications current for security and reliability, to make enhancements to existing software, and to address requests generated by changing business requirements. The project will also upgrade applications that support the CE&O Portfolio. The value of regular upgrades to applications in the CE&O Portfolio lies in: (1) enhancing security protections; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the CE&O Portfolio. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for areas supported by the CE&O Portfolio. Prior to implementing the applications, a review is completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements are considered. This project makes ongoing upgrades and support for the applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes and to meet legally required system changes. Timing for an application upgrade is based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks.

- The **Application Currency and Enhancements - CE&O - Capital** project requires $374,112 in capital and $144,540 in O&M in the test year. This project will utilize both capital and O&M funding to keep applications current for security and reliability, to make enhancements to existing software, and to address requests generated by changing business requirements. O&M is included in this project to complete the preliminary planning phase for capital enhancements and upgrades. The project will also upgrade the applications that support the CE&O Portfolio. The value of regular upgrades to applications in the CE&O Portfolio lies in: (1) enhancing security protections; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for CE&O. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for the CE&O Portfolio. Prior to implementing the applications, a review is completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements are considered. This project makes ongoing upgrades and support for the applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes and to meet legally required system changes. Timing for an application upgrade is based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks.

- The **Application Currency and Enhancements - Analytics, Cloud, DevOps, and Architecture ("ACDA") - O&M** project requires $113,067 in O&M in the test year. This project will apply O&M funding to keep applications current for security and reliability and make enhancements to existing software and to address requests generated by changing business requirements. The project will also upgrade the applications that support the ACDA Portfolio. The value of regular upgrades to applications in the ACDA Portfolio lies in: (1) enhancing security protections; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for ACDA Portfolio. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for the ACDA Portfolio. Prior to implementing the applications, a review is completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements are considered. This project makes ongoing upgrades and support for the applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes and to meet legally required system changes. Timing for an application upgrade is based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks.

- The **Application Currency and Enhancements - ACDA - Capital** project requires $56,810 in capital and $56,810 in O&M in the test year. This project will utilize both capital and O&M funding to keep applications current for security and reliability, to make enhancements to existing software, and to address requests generated by changing business requirements. O&M is included in this project to complete the preliminary planning phase for capital enhancements and upgrades. The project will also upgrade applications that support the ACDA Portfolio. The value of regular upgrades to applications in the ACDA Portfolio lies in: (1) enhancing security protections; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the ACDA Portfolio. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for areas supported by the ACDA Portfolio. Prior to implementing the applications, a review is completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements are considered. This project makes ongoing upgrades and support for the applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes and to meet legally required system changes. Timing for an application upgrade is based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks.

- The **Application Currency and Enhancements – Corporate Services - Capital** project requires $717,048 in capital and $81,736 in O&M in the test year. This project will utilize both capital and O&M funding to keep applications current for security and reliability, to make enhancements to existing software, and to address requests generated by changing business requirements. O&M is included in this project to complete the preliminary planning phase for capital enhancements and upgrades. The project will also upgrade applications that support the Corporate Services Portfolio. The value of regular upgrades to applications in the Corporate Services Portfolio lies in: (1) enhancing security protections; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Finance; HR; Learning & Development; Legal; Governmental, Regulatory and Public Affairs; Corporate Security; and Strategy and IT Governance. Prior to implementing the applications, a review is completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements are considered. This project makes ongoing upgrades and support for the applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes and to meet legally required system changes. Timing for an application upgrade is based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks.

- The **Application Currency and Enhancements – Corporate Services - O&M** project requires $239,976 in O&M in the test year. This project will apply O&M funding to keep applications current for security and reliability, to make enhancements to existing software, and to address requests generated by changing business requirements. The project will also upgrade applications that support the Corporate Services Portfolio. The value of regular upgrades to applications in the Corporate Services Portfolio lies in: (1) enhancing security protections; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Finance; HR; Learning & Development; Legal; Governmental, Regulatory and Public Affairs; Corporate Security; and Strategy and IT Governance. Prior to implementing the applications, a review is completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements are considered. This project makes ongoing upgrades and support for the applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes and to meet legally required system changes. Timing for an application upgrade is based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks.

- The **Application Currency and Enhancements - Operations - Capital** project requires $576,964 in capital and $43,362 in O&M in the test year. This project will utilize both capital and O&M funding to keep applications current for security and reliability, to make enhancements to existing software, and to address requests generated by changing business requirements. O&M is included in this project to complete the preliminary planning phase for capital enhancements and upgrades. The project will also upgrade applications that support the Operations Portfolio. The value of regular upgrades to applications in the Operations Portfolio lies in: (1) enhancing security protections; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Operations. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for the Operations area. Prior to implementing the applications, a review is completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements are considered. This project makes ongoing upgrades and support for the applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes and to meet legally required system changes. Timing for an application upgrade is based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks.

- The **Application Currency and Enhancements - TEOS - Capital** project requires $304,832 in capital and $4,417 in O&M in the test year. This project will utilize both capital and O&M funding to keep applications current for security and reliability, to make enhancements to existing software, and to address requests generated by changing business requirements. O&M is included in this project to complete the preliminary planning phase for capital enhancements and upgrades. The project will also upgrade applications that support the TEOS Portfolio. The value of regular upgrades to applications in the TEOS Portfolio lies in: (1) enhancing security protections; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage new functionality available in the upgrades. Requests for this funding are governed by a cross-functional board comprised of representatives from each area. The board meets monthly to evaluate and prioritize the work and to assess requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing IT software application investments for the TEOS Portfolio. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; and (4) updating documentation related to the integration changes. Additionally, enhancement requests are fulfilled to provide functionality for the TEOS Portfolio. Prior to implementing the applications, a review is completed to identify the best solution. During that review, the alternatives of delaying the timing of the individual upgrades and zero budget allocation for enhancements are considered. This project makes ongoing upgrades and support for the applications possible and fortifies the Company's ability to make software changes as part of process improvements and regulatory changes and to meet legally required system changes. Timing for an application upgrade is based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks.

Q. Please explain the Digital Foundations and Capabilities projects.

A. These are the Digital Foundations and Capabilities projects:

- The **Digital - Data and Analytics in the Cloud** project requires $1,048,400 in capital and $132,254 in O&M. This project will extend the Company's current data and analytics environment into a cloud environment, which will enable data and analytics at-scale and enable the delivery of outcomes for the Natural Gas Delivery Plan, Electric Grid Integration, customer programs, and other business needs. The project will add value by: (1) providing the ability to perform data analytics at-scale; (2) allowing the ability to leverage the leading machine learning ("ML") and artificial intelligence ("AI") tools to enable predictive and prescriptive analytics at-scale; (3) providing the ability to provision infrastructure at-scale rapidly; (4) enabling pay for use; (5) empowering faster prototyping, testing, and deployment of analytics solutions; (6) reducing total cost of ownership; and (7) providing operational tools for monitoring, incident management, and resolution. The project scope includes: (1) the execution of data analytics at-scale without scalability constraints; (2) flexible transitioning with technology platforms as they evolve; (3) the use of out-of-the-box ML and AI tools provided by cloud vendors; (4) new services and innovations on the cloud platform; (5) capacity pay per use; and (6) the foundation for future cloud migration and maintenance. The alternative considered to a cloud solution is to continue to expand the on-premise infrastructure and purchase multiple tools to solve individual capability gaps. The Company did not choose this alternative because it is more costly than cloud due to higher infrastructure costs and more manpower required for implementation.

- The **Digital - Data Governance** project requires $760,992 in capital and $240,405 in O&M. This project will be used to establish data governance roles and responsibilities, processes, and the purchase of a tool to support best practices across the enterprise. The project will add value by: (1) increasing productivity of data analysts across the Company by reducing time spent cleaning data; (2) improving business planning; (3) maximizing the use of data to make decisions; and (4) discovering where data lives and the definition of data elements. The project scope includes: (1) initializing key data domains and ownership across the Company through the creation of an overarching data governance process and establishing processes and cadence for introducing new data elements into their domain; (2) enabling people to become functional and technical data stewards through education; and (3) implementing technology through the selection of a data cleansing, data quality, data extract, and transformation tool, including enterprise-wide semantic definition. Alternatives considered include: (1) not implementing a data governance solution, potentially limiting the Company's productivity due to data quality and accessibility; (2) developing an internal tool to help manage the Company's data footprint; or (3) purchasing a third-party solution. Purchasing a third-party solution was selected because the skillsets required to internally develop such tools are not available, and it would take a larger investment to upskill or hire individuals with this experience.

- The **Digital - Application Programming Interface ("API") Fabric** project requires $602,736 in capital and $175,692 in O&M. This project provides foundational capabilities around APIs, which are a set of technologies used to integrate applications within the Company and, more importantly, with external third-party applications. In short, APIs allow two applications to talk to each other. This is currently a gap and is a key technical capability needed to enable multiple IT projects related to the Company's strategy for clean energy like: Electric Interconnection Billing and Payments; MISO Market User Interface Changes; Utility Analytics Mis-Phasing/Power Quality/Outage; Field Contractor Work Management Technology Enablement; Work Management Scheduling, Analytics and Reporting; DERMS; and Google X. Similarly, this API foundational capability will enable customer-focused projects like: Business Customer Interval Web Portal, Bring Your Own Thermostat Pilot, Customer Relationship Management Product Suite, and Large Customer Rate Tool. The project will add value by: (1) implementing functionality to perform API services at-scale; (2) allowing partners to integrate with the Company's internal applications; (3) providing the ability to reuse integrations; (4) enabling monitoring of API traffic; (5) implementing functionality to perform API throttling (i.e., traffic management); (6) visualizing API traffic and analytics through key performance indicators; (7) enabling faster prototyping, testing, and deployment of integrations; and (8) providing operational tools for monitoring, incident management, and resolution. The project scope includes: (1) evaluating multiple API management tool vendors; (2) executing API on-boarding for a number of external partners without scalability constraints; and (3) configuring and deploying API services with out-of-the-box operations tooling to achieve faster speed to market. Two alternatives were explored and determined to be non-viable: (1) remain on current Tibco API product that is part of their ESB platform, which does not support the future needs of the Company including efforts to modernize the grid; and (2) scale back on the implementation of the API fabric and complete over a longer period, which would negatively impact other projects. These alternatives were not selected because the API fabric is foundational and needs to be completed to support other projects. The current scope and direction is the best fit to support current Company initiatives.

- The **Digital - Foundation Enhancements** project requires $271,578 in capital and $210,540 in O&M. The Company's digital foundation consists of platforms that provide capabilities for analytics, cloud, integration, content management, and network communications. These capabilities are the underlying foundation for digital systems needed to help achieve the Company's goals for clean energy, gas system reliability and safety, and the products, services, and experience customers expect. This project ensures that the Company keeps these foundational platforms updated with the latest software releases to keep the platforms secure while adding features like newer advanced analytics capabilities or new bundled and improved cloud service offerings. In the near future, it is expected that more smart devices will exist on the grid and pipelines and in customer's homes. The ability to communicate securely and in a timely manner in order to manage the electric and gas systems effectively will require upgrading underlying platforms to conform with the latest security and communication requirements. The project will add value by: (1) enabling advanced and new functionality; (2) increasing the reliability and resiliency of Company applications; and (3) ensuring flexible, configurable platforms to scale and adapt with an evolving business landscape and customer expectations. As part of the review process, the alternative considered was not providing the funding for foundational enhancements. However, this limits the Company's ability to meet customer expectations, reduce security risks, and maintain system performance.

- The **Digital - Work Automation** project requires $151,723 in capital and $157,740 in O&M. This project will implement and enhance Robotic Process Automation ("RPA"), ML, and AI tools. The project adds value to the Company by providing the foundation that will allow business areas to automate key processes based on individual use cases. Each use case will deliver benefits, reduce errors, and improve overall productivity to support Company customers and employees. The scope of the project will be to leverage the existing platforms to provide the foundation of RPA, ML, and AI to support use cases across all business units. The alternative considered was to continue with existing manual processes, which prevents the business areas from reducing the risk of manual errors or improving productivity through automation. Providing a foundational automation platform allows the Company to maximize the benefits of automation in support of customers and employees.

- The **Business Process Performance Monitoring — AppDynamics** project requires $18,390 in O&M. This project will deploy the AppDynamics tool across enterprise applications like SAP, OMS, and other business critical systems. This project will create value for the Company by providing faster system restoration through automation of system troubleshooting that pinpoints the software or hardware that is causing the problem. The project scope includes: (1) SAP; (2) OMS; (3) Advanced Device Metering System; and (4) other enterprise applications. The Company evaluated multiple products for this project and AppDynamics fit the cost and functionality expectations. The others were cost prohibitive and lacked the functionality of the product selected.

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

A. These are the projects included within the Security area:

- The **AccessNOW** project requires $346,400 in capital and $33,000 in O&M. This project will implement configurable identity access management functionality and best practices and will enforce compliance. This project will add value by: (1) reducing waste and failure points through automation; (2) improving and standardizing the business partner experience; (3) centralizing access management; (4) ensuring regulatory compliance; and (5) ensuring system stability and continuous improvement. The project scope includes implementing additional integrations to Active Directory domains that are not currently connected to the AccessNOW application and integrating with the Company's SAP system to allow for automation of SAP role access provisioning. In addition, the project scope includes: (1) design, configuration, and testing of technical connections; (2) completion of application support pack upgrades to the next versions to maintain system stability and to stay current with vendor releases; and (3) review and implementation of enhancements to improve and standardize the business partner experience. As part of the review process the alternative considered was using manual processes. This option was not chosen because it was deemed too costly and inefficient.

- The **Fusion Center** project requires $304,545 in capital and $77,116 in O&M. This project will procure a location to combine the Security Command Center and the Cyber Security Incident Response Team. This project will focus on constructing a physical office space to facilitate these two teams working in a collaborative fashion. This project will add value by: (1) co-locating physical and cyber team members for process efficiencies and better integration of tools in the event of a security incident that requires both teams' collaboration; (2) having a dedicated emergency operations area for use in the event of a security incident (cyber or physical or both) providing the tools needed to keep stakeholders informed; (3) evaluating and potentially implementing a shared intelligence capability across both areas; and (4) further integrating existing processes and workflows. The project scope encompasses building an integrated Security Command Center across physical and cyber security domains that takes into consideration physical space, technology, process integration, analytics, and intelligence capabilities without changing existing organizational structures. As part of the review process, the alternative considered was to continue to run a separate Security Command Center for physical security incident response and a separate Cyber Security Incident Response Center. The two centers would continue to run separate, non-integrated systems and tools. This option was not chosen as it does not provide the integrated space and tools needed for physical and cyber security teams to collaborate to resolve critical incidents that pose both a physical and cyber threat.

- The **Fusion Center Technologies** project requires $692,800 in capital and $66,000 in O&M. This project will further integrate the physical and cyber security teams through the implementation of new technologies. This project will evaluate, replace, and implement new capabilities for monitoring physical sites and technology assets, significantly improving the Company's quality and timeliness of detection and response to both physical and cyber security incidents. Completion of this project will provide value to the Company through: (1) implementing a new toolset to move MITRE Adversarial Tactics, Techniques, & Common Knowledge ("ATT&CK") coverage from 30% to 80% (MITRE ATT&CK Framework is an industry-leading framework to detect malicious activity); (2) replacing the vulnerability management platform, Qualys, which has several capability gaps estimated to be remedied at a significant cost; and (3) evaluating and implementing a biometric toolset, such as facial recognition, to eliminate an unauthorized individual to follow an authorized individual into a facility and to proactively alert of unwanted or unknown personnel at Company facilities. The scope of this project encompasses: (1) all endpoints and servers, and all facilities that house employees; (2) defining system scalability requirements; (3) designing new platform architecture; and (4) purchasing and implementing hardware and software once alternatives are reviewed. The alternative considered was to remain on current toolsets and not implement additional physical security countermeasures, impacting the quality and timeliness of detection and response to both physical and cyber security incidents. The Company is choosing to replace and implement new capabilities to provide further efficiencies and capabilities.

- The **Replace and Re-badge** project requires $346,525 in capital and $33,000 in O&M. This project will: (1) replace and re-badge existing card readers with human interface device multiclass readers; and (2) re-badge employees and contractors with more secure badges, mitigating cloning vulnerabilities with the current legacy technology being used. The value of completing the project is avoidance of the security risk for one of the Company's key security controls. The scope of the implementation includes: (1) replacing existing card readers; (2) re-badging to I-class badges; and (3) encrypting the new badges. As part of the review process, the alternative considered was to continue with current badge readers, which have a potential to be cloned. This alternative was not chosen due to the potential to high likelihood of security vulnerabilities and risks.

- The **Physical Security Asset Refresh** project requires $1,197,840 in capital. This project will enhance or replace physical security assets to provide improved visibility into potential security concerns and resolve incidents. The Company has several thousand physical security asset devices currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. The value provided by completing the project is to: (1) maintain compliance; (2) reduce redundancies and gaps in functionality; and (3) optimize overall performance. An integrated solution is efficient and allows for centralized management; situational awareness; real-time monitoring; compliance with regulations and guidelines; and faster, more effective and consistent responses to emergencies and incidents. 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. As part of the review process the alternative considered was not to do this work, but this would assume the risk that the Company will not meet FERC requirements.

Following are the projected capital costs for Physical Security Asset Referesh project attributable to the electric business for 2020 and 2021 test year in the table below.

Site	Equipment	Total 2020 Units	Total 2021 Units	Total 2020 Dollars	Total 2021 Test Year Dollars	Electric Allocation Dollars
Adrian	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00
Backup SCC	Install/Replace Assets & Furniture	1	0	$120,000.00	$0.00	$0.00
Bad Axe	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00
Badge Printers	Install/Replace Badge Printers	6	0	$75,000.00	$0.00	$0.00
Battle Creek	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00
Bay City SC	Install/Replace Cameras & Card Readers	4	0	$75,000.00	$0.00	$0.00
Bellevue	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00
Campbell Plant	Install/Replace Cameras	20	0	$150,000.00	$0.00	$0.00
Clare	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00
Cross Winds Energy Park	Install/Replace Network Video Recorder	1	0	$40,000.00	$0.00	$0.00
Flint	Install/Replace Cameras & Network Video Recorder	6	0	$75,000.00	$0.00	$0.00
Fremont SC	Install/Replace Cameras & Network Video Recorder	4	0	$30,000.00	$0.00	$0.00
Grand Rapids SC	Install/Replace Cameras & Network Video Recorder	4	0	$65,000.00	$0.00	$0.00

Groveland	Install/Replace Cameras & Card Readers	2	0	$15,000.00	$0.00	$0.00
Hamilton	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00
Jackson CEIC	Install/Replace Cameras	4	0	$20,000.00	$0.00	$0.00
Kalamazoo SC	Install/Replace Cameras & Network Video Recorder	12	0	$75,000.00	$0.00	$0.00
Laingsburg	Install/Replace Cameras	4	0	$30,000.00	$0.00	$0.00
Lake Winds	Install/Replace Network Video Recorder	1	0	$30,000.00	$0.00	$0.00
Lansing	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00
Livonia	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00
LPS	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00
Ludington SC	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00
Macomb	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00
Muskegon DPO	Install/Replace Cameras	8	0	$36,000.00	$0.00	$0.00
OEP Parking - Gate Arms	Install/Replace Cameras, Card Readers and Gate Arm	16	0	$45,000.00	$0.00	$0.00
Owosso	Install/Replace Cameras	4	0	$35,000.00	$0.00	$0.00
Page Ave Sub	Thermal Radar Test	2	0	$85,000.00	$0.00	$0.00
Parnall NVR 1	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00

Ray Compressor	Install/Replace Cameras & Network Video Recorder	6	0	$75,000.00	$0.00	$0.00
Refresh Security Trailer 1	Install/Replace Cameras	4	0	$20,000.00	$0.00	$0.00
Refresh Security Trailer 2	Install/Replace Cameras	4	0	$20,000.00	$0.00	$0.00
Royal Oak	Install/Replace Cameras & Network Video Recorder	6	0	$75,000.00	$0.00	$0.00
Saginaw SC	Install/Replace Cameras & Network Video Recorder	6	0	$60,000.00	$0.00	$0.00
St. Clair	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00
White Pigeon	Install/Replace Network Video Recorder	1	0	$15,000.00	$0.00	$0.00
White Pigeon - Valve site	Install/Replace Cameras & Intrusion Detection System	4	0	$350,000.00	$0.00	$0.00
Battle Creek	Install/Replace Cameras		15	$0.00	$100,000.00	$57,040.00
Freedom Compressor	Install/Replace Cameras		6	$0.00	$200,000.00	$114,080.00
Groveland	Install/Replace Cameras		6	$0.00	$30,000.00	$17,112.00
Jackson Meter Tech	Install/Replace Cameras		12	$0.00	$85,000.00	$48,484.00
Jackson Service Center	Install/Replace Cameras		30	$0.00	$135,000.00	$77,004.00
Lansing	Install/Replace Cameras		15	$0.00	$100,000.00	$57,040.00
Macomb	Install/Replace Cameras		10	$0.00	$45,000.00	$25,668.00
Northville Compressor	Install/Replace Cameras		6	$0.00	$200,000.00	$114,080.00

One Energy Plaza	Install/Replace Cameras		25	$0.00	$175,000.00	$99,820.00
Overisel Compressor	Install/Replace Cameras		6	$0.00	$200,000.00	$114,080.00
Parnall	Install/Replace Cameras		25	$0.00	$175,000.00	$99,820.00
Parnall East	Install/Replace Cameras		12	$0.00	$85,000.00	$48,484.00
Pontiac Direct Payment Office	Install/Replace Cameras		8	$0.00	$75,000.00	$42,780.00
Ray Compressor	Install/Replace Cameras		15	$0.00	$100,000.00	$57,040.00
South Monroe	Install/Replace Cameras		8	$0.00	$75,000.00	$42,780.00
White Pigeon Compressor	Install/Replace Cameras		15	$0.00	$100,000.00	$57,040.00
Software, labor, contractor and overhead and other costs				$289,000.00	$220,000.00	$125,488.00
Total Electric Allocation				$2,100,000.00	$2,100,000.00	**$1,197,840.00**

Following are the actual and projected capital costs for Physical Security Asset Refresh project attributable to the electric business for 2018 and 2019 in the table below.

Site	Equipment	Total 2018 Units*	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Electric Allocation Dollars	2019 Electric Allocation Dollars
Alma	Install/Replace Cameras		0	$45,165.00	$0.00	$26,286.03	$0.00
Battle Creek	Install/Replace Cameras		0	$62,521.70	$0.00	$36,387.63	$0.00
Benzonia	Install/Replace Cameras		0	$31,313.00	$0.00	$18,224.17	$0.00
Birch Run	Install/Replace Cameras		0	$36,521.00	$0.00	$21,255.22	$0.00
Boyne City	Install/Replace Cameras		0	$31,452.00	$0.00	$18,305.06	$0.00
Cadillac	Install/Replace Cameras		0	$39,030.00	$0.00	$22,715.46	$0.00
Corporate Garage	Install/Replace Cameras		0	$15,749.00	$0.00	$9,165.92	$0.00

East Kent	Install/Replace Cameras		0	$36,689.00	$0.00	$21,353.00	$0.00
Gaylord	Install/Replace Cameras		0	$60,821.32	$0.00	$35,398.01	$0.00
Grand Rapids	Install/Replace Cameras		0	$63,538.00	$0.00	$36,979.12	$0.00
Greenville	Install/Replace Cameras		0	$48,245.00	$0.00	$28,078.59	$0.00
Hastings	Install/Replace Cameras		0	$26,711.00	$0.00	$15,545.80	$0.00
Howell	Install/Replace Cameras		0	$114,187.00	$0.00	$66,456.83	$0.00
Huron	Install/Replace Cameras		0	$74,502.54	$0.00	$43,360.48	$0.00
IRC	Install/Replace Cameras		0	$44,700.00	$0.00	$26,015.40	$0.00
Midland	Install/Replace Cameras		0	$32,590.00	$0.00	$18,967.38	$0.00
Lansing SC	Install/Replace Cameras		0	$80,496.00	$0.00	$46,848.67	$0.00
Lansing State Building	Install/Replace Cameras		0	$7,979.00	$0.00	$4,643.78	$0.00
Lansing	Install/Replace Cameras		0	$38,638.00	$0.00	$22,487.32	$0.00
Ludington	Install/Replace Cameras		0	$117,659.07	$0.00	$68,477.58	$0.00
Marshall	Install/Replace Cameras		0	$49,826.00	$0.00	$28,998.73	$0.00
Marion	Install/Replace Cameras		0	$25,579.00	$0.00	$14,886.98	$0.00
Mio	Install/Replace Cameras		0	$36,013.04	$0.00	$20,959.59	$0.00
Norton Shores	Install/Replace Cameras		0	$65,563.00	$0.00	$38,157.67	$0.00
OEP	ASM300 Software		0	$32,256.00	$0.00	$18,772.99	$0.00
OEP	Install/Replace Cameras		0	$56,197.81	$0.00	$32,707.13	$0.00
Overisel	Install/Replace Cameras & Network Video Recorder		0	$78,448.77	$0.00	$45,657.18	$0.00
Owosso	Install/Replace Cameras		0	$51,391.00	$0.00	$29,909.56	$0.00
Parnall	IT Card Reader/Camera		0	$34,680.00	$0.00	$20,183.76	$0.00
Royal Oak	Install/Replace Cameras		0	$17,855.00	$0.00	$10,391.61	$0.00
Saginaw	Install/Replace Cameras		0	$29,553.00	$0.00	$17,199.85	$0.00
South Haven	Install/Replace Cameras		0	$104,054.00	$0.00	$60,559.43	$0.00
St.Clair	Install/Replace Cameras		0	$238,761.00	$0.00	$138,958.90	$0.00

Thetford Generation	Install/Replace Cameras		0	$59,379.00	$0.00	$34,558.58	$0.00
Trail Street	Install/Replace Cameras		0	$66,812.00	$0.00	$38,884.58	$0.00
Traverse City	Install/Replace Cameras		0	$17,866.00	$0.00	$10,398.01	$0.00
Adrian	Install/Replace Cameras	0	6	$0.00	$17,655.00	$0.00	$10,070.41
Alcona	Install/Replace Cameras & Network Video Recorder	0	8	$0.00	$29,949.00	$0.00	$17,082.91
Allegan	Install/Replace Cameras & Network Video Recorder	0	6	$0.00	$19,885.00	$0.00	$11,342.40
Alma	Install/Replace Cameras & Network Video Recorder	0	9	$0.00	$43,244.00	$0.00	$24,666.38
Bad Axe	Install/Replace Cameras	0	5	$0.00	$17,592.00	$0.00	$10,034.48
Battle Creek	Install/Replace Cameras & Card Readers	0	3	$0.00	$30,038.00	$0.00	$17,133.68
Bay City	Install/Replace Cameras	0	3	$0.00	$13,541.00	$0.00	$7,723.79
Cadillac	Install/Replace Cameras	0	4	$0.00	$19,990.00	$0.00	$11,402.30
Caro	Install/Replace Cameras & Network Video Recorder	0	4	$0.00	$21,974.00	$0.00	$12,533.97
Clare	Install/Replace Cameras	0	5	$0.00	$15,482.00	$0.00	$8,830.93
Commonwealth	Install/Replace Cameras	0	6	$0.00	$15,020.00	$0.00	$8,567.41
Cooke	Install/Replace Cameras & Network Video Recorder	0	6	$0.00	$26,493.00	$0.00	$15,111.61
Cross Winds	Install/Replace Cameras	0	4	$0.00	$10,349.00	$0.00	$5,903.07
Croton	Install/Replace Cameras & Network Video Recorder	0	8	$0.00	$52,044.00	$0.00	$29,685.90
Five Channels	Install/Replace Cameras & Network Video Recorder	0	16	$0.00	$64,075.00	$0.00	$36,548.38
Foote	Install/Replace Cameras & Network Video Recorder	0	6	$0.00	$24,941.00	$0.00	$14,226.35

Groveland	Install/Replace Cameras & Network Video Recorder	0	9	$0.00	$24,423.00	$0.00	$13,930.88
Hamilton	Install/Replace Cameras & Network Video Recorder	0	6	$0.00	$18,722.00	$0.00	$10,679.03
Hardy	Install/Replace Cameras & Network Video Recorder	0	11	$0.00	$46,989.00	$0.00	$26,802.53
Hodenpyle	Install/Replace Cameras, Network Video Recorder & Intercom	0	10	$0.00	$52,483.00	$0.00	$29,936.30
Jackson Service Center	Install/Replace Cameras	0	9	$0.00	$36,144.00	$0.00	$20,616.54
Karn	Install/Replace Cameras & Network Video Recorder	0	14	$0.00	$106,390.00	$0.00	$60,684.86
Lake Winds	Install/Replace Cameras	0	83	$0.00	$117,942.00	$0.00	$67,274.12
Livonia	Install/Replace Cameras	0	11	$0.00	$25,297.00	$0.00	$14,429.41
Loud	Install/Replace Cameras & Network Video Recorder	0	9	$0.00	$31,916.00	$0.00	$18,204.89
Ludington Pump Storage	Install/Replace Cameras	0	10	$0.00	$26,960.00	$0.00	$15,377.98
Macomb	Install/Replace Cameras	0	8	$0.00	$30,759.00	$0.00	$17,544.93
Midland	Install/Replace Cameras & Card Readers	0	9	$0.00	$49,802.00	$0.00	$28,407.06
Mio	Install/Replace Cameras	0	7	$0.00	$25,127.00	$0.00	$14,332.44
Northville	Install/Replace Cameras, Network Video Recorder & Card Readers	0	20	$0.00	$142,295.00	$0.00	$81,165.07
OEP	Install/Replace Cameras & Network Video Recorder	0	91	$0.00	$369,884.00	$0.00	$210,981.83
Overisel	Install/Replace Cameras	0	3	$0.00	$12,960.00	$0.00	$7,392.38
Overisel	Gate Camera Monitors Cabling	0	1	$0.00	$6,900.00	$0.00	$3,935.76

Parnall	Install/Replace Cameras & Network Video Recorder	0	36	$0.00	$178,909.00	$0.00	$102,049.69
Pontiac	Install/Replace Cameras	0	4	$0.00	$7,460.00	$0.00	$4,255.18
Roger	Install/Replace Cameras & Network Video Recorder	0	7	$0.00	$30,788.00	$0.00	$17,561.48
Saginaw	Install/Replace Cameras	0	7	$0.00	$32,635.00	$0.00	$18,615.00
South Haven	Install/Replace Cameras, Network Video Recorder & Card Readers	0	39	$0.00	$75,709.00	$0.00	$43,184.41
Traverse City	Install/Replace Cameras & Card Readers	0	10	$0.00	$59,980.00	$0.00	$34,212.59
Webber	Install/Replace Cameras & Network Video Recorder	0	14	$0.00	$56,243.00	$0.00	$32,081.01
West Branch	Install/Replace Cameras & Network Video Recorder	0	12	$0.00	$34,614.00	$0.00	$19,743.83
Zeeland	Install/Replace Cameras	0	21	$0.00	$70,616.00	$0.00	$40,279.37
Software, labor, contractor and overhead and other costs				$34,257.89	$876,981.09	$19,938.09	$500,230.01
Total Electric Allocation				$2,007,000.14	$2,971,200.09	**$1,168,074.08**	**$1,694,772.53**

*Unit data not available in 2018 for this program; line items include software, labor and, contractor costs

- The **Cyber Security Enhancements** project requires $118,800 in O&M. This project will: (1) fund emerging or unplanned cyber security activities resulting from audits, incidents, or a changing threat landscape; and (2) support initiatives that may not meet the criteria for a formal project. Requests for this funding are governed by project management and the security governance board, which is comprised of representatives from each area of Security and meets monthly to evaluate and prioritize the work. The board assesses requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in scope are small changes and functionality improvements to existing software application investments for Security. The enhancement requests are fulfilled to provide functionality for areas such as security program management, cyber security incident response, corporate physical security, compliance, privacy and risk management, and cyber security engineering and standards. As part of the review process, the alternative considered was not to upgrade or enhance software or hardware, which could reduce the Company's ability to respond to future threats and vulnerabilities.

- The **Asset Refresh Program - Cyber Security** project requires $256,680 in capital. This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions. This program includes projects that bring value to the Company by maintaining the currency of the security infrastructure and core enterprise software. These are used to ensure the stability of technology for business operations. This project will support continued systems stability. The scope encompasses: (1) evaluation, validation, and replacement of cyber security firewalls and servers; and (2) asset and application upgrades. As part of the review process, the alternative considered was not to upgrade or replace assets as required, which is likely to introduce security risks, system vulnerabilities, and out-of-warranty repair costs.

  Following are the projected capital costs for ARP – Cyber Security project attributable to the electric business for 2020 and 2021 test year in the table below.

Units	**Avg. Unit Cost**	**Total 2020 Units**	**Total 2021 Units**	**Total 2020 Dollars**	**Total 2021 Dollars**	**Electric Allocation Dollars**
CyberArk Appliances	$20,000.00	5	0	$100,000.00	$0.00	$0.00
OT High End PC/Server	$25,000.00	0	2	$0.00	$50,000.00	$28,520.00
Security Analytics Server Replacements	$25,000.00	8	10	$200,000.00	$250,000.00	$142,600.00
Software, labor, contractor and overhead and other costs				$150,000.00	$150,000.00	$85,560.00
Total Electric Allocation				$450,000.00	$450,000.00	**$256,680.00**

Following are the actual and projected capital costs for ARP – Cyber Security project attributable to the electric business for 2018 and 2019 in the table below.

Units	Avg. Unit Cost	Total 2018 Units	Total 2019 Units	Total 2018 Dollars	Total 2019 Dollars	2018 Electric Allocation Dollars	2019 Electric Allocation Dollars
Server Replacement	$119,562.67	1	0	$119,562.67	$0.00	$69,585.47	$0.00
Servers	$16,950.00	1	0	$16,950.00	$0.00	$9,864.90	$0.00
PA-3020 Refresh	$2,156.00	1	0	$2,156.00	$0.00	$1,254.79	$0.00
PA-5060's Refresh	$14,014.00	2	0	$28,028.00	$0.00	$16,312.30	$0.00
Reporter Refresh	$81,340.30	1	0	$81,340.30	$0.00	$47,340.05	$0.00
Mount Trays	$173.99	44	0	$7,655.56	$0.00	$4,455.54	$0.00
Security Analytics Refresh	$51,409.00	0	5	$0.00	$257,045.00	$0.00	$146,618.47
Security Analytics Net New Hardware	$20,700.00	0	4	$0.00	$82,800.00	$0.00	$47,229.12
Security Analytics High Availability Appliance	$3,921.97	0	4	$0.00	$15,687.88	$0.00	$8,948.37
Firewall Replacement	$38,500.00	0	4	$0.00	$154,000.00	$0.00	$87,841.60
Software, labor, contractor and overhead and other costs				$106,460.57	$120,685.60	$61,960.05	$68,839.07
Total Electric Allocation				$362,153.10	$630,218.48	**$210,773.10**	**$359,476.62**

- The **Data Governance** project requires $1,108,480 in capital and $33,000 in O&M. This project will develop an enterprise-wide data governance solution as an aspect of an Enterprise Data Privacy and Management Plan. Completion of this project will provide value to the Company through programmatic data governance resulting in increased data quality which will: (1) decrease operational costs; (2) increase employee satisfaction and productivity; (3) enhance system performance efficiencies; and (4) support better informed decision making. The scope of this project encompasses: (1) achieving consistency in collecting and reporting data across various organizational users and source systems; (2) achieving high quality in the collection, maintenance, analysis, and reporting of data; (3) responding to data issues; (4) promoting and ensuring consistent enterprise-wide data definitions, increasing controls regarding data creation, modification, and access; (5) proposing and implementing system controls for maintaining data quality (e.g., field-level validation, reporting, batch job cleansing); (6) facilitating the development of a data quality assurance process, including policy, process, and system (including system access) reviews against data; and (7) creating a process to include a holistic review of data management methodology for the effective collection, management, and access for data quality control. Alternatives considered include: (1) remain at the current state and not implement a data governance solution; (2) evaluate, select, and implement a technology solution to fulfill the Company's data governance needs; or (3) determine if any existing solutions the Company has built or purchased can meet the needs. The alternative selected is to move forward with implementing a data governance solution. A part of the project will be to evaluate both existing and new technology solutions.

- The **Radar Intrusion Detection** project requires $1,039,200 in capital and $33,000 in O&M. This project will integrate and deploy new radar detection technology to enable the detection and tracking of individuals at Company sites. The radar would alert in real time and allow for the dispatch of Security or law enforcement to investigate. Completion of this project will provide value to the Company through evaluating and selecting a more reliable intrusion detection solution that reduces the number of false alarms and prevent resources from being sent to a site for unnecessary investigations. The scope of this project encompasses: (1) assessing radar intrusion detection solutions to obtain a solution that fits the needs of the Company; (2) establishing a priority list of sites where the solution will be rolled out; and (3) installing updated radar intrusion at physical sites in the Company’s service territory with a focus on critical infrastructure sites, including but not limited to gas compressor stations, electric substations, and hydro-electric sites. Alternatives considered include: (1) keeping the current fence intrusion detection solution; or (2) evaluating, selecting, and implementing a new intrusion detection solution. The preferred option is to implement a new solution, given limitations with the current solution that result in multiple false alarms that must be investigated.

- The **Lock and Key Management System** project requires $692,800 in capital and $33,000 in O&M. This project will identify and implement a physical smart lock and key management system throughout the Company's service territories. Current estimates show there are approximately 10,000–14,000 locks throughout the state, and the Company has no system to properly manage ownership of specific physical keys and control who uses them to access sites. Completion of this project will provide value to the Company by: (1) assessing and taking inventory of current locks and keys that are used throughout the state; (2) determining core functionalities needed to ensure proper lock and key management state wide; and (3) reviewing and implementing a solution to give the physical security team a lock and key management capability. The scope of this project includes: (1) assessing the type of locks and keys used, and at what sites they will be needed to properly plan this project; (2) determining the levels and functions of different smart lock systems available; and (3) purchasing and implementing a lock and key management system based on assessment findings. Alternatives considered include: (1) remain at the current state and forfeit implementing new lock and key management capabilities; or (2) evaluate, select, and implement a smart lock and key solution. The preferred option is to mitigate known and observed risks with the lack of lock and key management capabilities.

- The **Email Protection** project requires $99,000 in O&M. This project will implement an enterprise-wide email filtering toolset to ensure protection against current cyber security risks, including malware and non-malware threats, email fraud, and ransomware. Completion of this project will provide value to the Company by: (1) evaluating and procuring a leading email filtering toolset; (2) configuring the toolset to help eliminate human error; and (3) implementing the toolset enterprise-wide for company email. The scope of this project encompasses protection for both incoming and outbound emails. The alternative considered was to continue with focused cyber security and phishing training programs for employees. Security awareness training has reached peak effectiveness. The Company is choosing to implement a technical solution to further mitigate the risk of phishing attacks caused by human error.

- The **Continuous Readiness in Information Security Program ("CRISP")** project requires $115,500 in O&M. This project will implement the continuous readiness in information security program, which is a cyber security tool coordinated by the Department of Homeland Security ("DHS"). The tool watches network traffic coming into and leaving our environment and attempts to identify attacks from highly skilled actors typically associated with other nations. Details regarding identified attacks are then anonymized and sent to DHS for analysis. CRISP does not identify cyber crime attacks or commodity malware. CRISP focuses on attackers who are motivated to impact critical infrastructure. Nearly all major utilities in the United States have or are in the process of implementing CRISP. Completion of this project will provide value to the Company by: (1) receiving alerts from DHS based upon classified intelligence regarding who is attacking the Company; (2) analyzing alerts to determine if the Company was impacted; (3) receiving alerts about attacks at other utilities, which will enable the Company to proactively mitigate potential future attacks; and (4) enabling the company to share threat intelligence with other utilities for the benefit our nation's critical infrastructure. The scope of this project encompasses: (1) forming an agreement with DHS; (2) procuring a network sensor; and (3) working through architecture designs, deployment, and testing of the network sensor. As part of the review process the alternative considered was not to implement CRISP, which limits the Company's ability to respond to future advanced threats and share information for the benefit of the nation.

Q. Are the expenditures identified here reasonable and prudent?

A. Yes. The capital and O&M expenditures requested in this case will help the Company achieve the outcomes of the IRP and EDIIP, continually improve the experience of customer's interactions with the Company, and maintain a reliable and secure technology base that is exposed to ever-increasing and more serious cyber security threats over time. Technology is the backbone of Company operations and two-way customer communications. The Company has demonstrated the prudency of project expenditures, support for its operational O&M requirements, and the inability to sustain O&M funding based on a five-year average.

The Company has described how digital investments will enable the IRP and EDIIP through increased visibility, monitoring, and control of the electric system; improved asset and work management capabilities; and advanced analytics. The Company thoroughly explained how O&M funding based on a five-year average requires it to prioritize dollars on operating, maintaining, and securing existing technology, and does not enable it to make important digital investments for the future. The Company explained how technology versions have fallen behind reasonable levels, and how funding based on a five-year average does not enable it to patch and upgrade its systems to reasonable levels of version currency, putting systems at risk of growing cyber security threats and increasing performance risks to systems that customers depend on.

Q. Does this conclude your direct testimony?

A. Yes.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

KEITH G. TROYER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Keith G. Troyer, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

A. I am the Director of Electric Grid Integration Contracts and Settlements in the Electric Supply Section of the Electric Grid Integration Department.

Q. Please describe your educational background and business experience.

A. I received the degree of Bachelor of Science in Engineering with a specialty in Civil Engineering from Michigan State University in 2008. In 2015, I became a Registered Professional Engineer in the state of Michigan. In 2018, I received a Master of Business Administration ("MBA") through Michigan State University's Executive MBA Program. In July 2009, I joined Consumers Energy as an Electric System Owner. In January 2011, I accepted a position as an Engineer in the Transactions and Resource Planning Section of Energy Supply. In that role, I was responsible for administration and coordination of the Company's Experimental Advanced Renewable Program ("EARP")-Solar ("EARP-Solar"), part of the Company's Renewable Energy Plan ("RE Plan"). I was involved in the development and implementation of the EARP-Solar expansion in 2011. In June 2013, I began taking on additional responsibilities associated with the RE Plan, including the calculation of the Transfer Price associated with renewable energy and capacity and the tracking of RE Credits ("RECs"). In 2014, I was also responsible for supervision of the implementation of the EARP-Anaerobic Digestion ("EARP-AD") pilot.

In December 2016, I transitioned to a new role where my supervisory and direct responsibilities included administering Power Purchase Agreements ("PPAs"), issuing solicitations for energy and capacity, and managing the Company's capacity position with Midcontinent Independent System Operator, Inc. ("MISO").

Q. What are your responsibilities as Director of Electric Grid Integration Contracts and Settlements?

A. My responsibilities include oversight of the Company's distribution and power purchase agreements, solicitations for energy and capacity, renewable energy compliance, distributed generation programs, and electric wholesale settlement activities.

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

A. Yes. I provided testimony in:

- Case No. U-17095-R (direct), the Company's 2013 Power Supply Cost Recovery ("PSCR") Reconciliation case, regarding 2013 RE Plan expenses recovered through PSCR;
- Case No. U-17631 (direct), the Company's 2013 RE Reconciliation case, regarding 2013 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;
- Case No. U-17317-R (direct), the Company's 2014 PSCR Reconciliation case, regarding 2014 RE Plan expenses recovered through PSCR;
- Case No. U-17792 (direct and rebuttal), the 2015 biennial review of the Company's RE Plan, regarding RE Plan expenses recovered through the PSCR, RE compliance, new renewable capacity compliance, and RE programs;
- Case No. U-17803 (direct), the Company's 2014 Renewable Cost Reconciliation case, regarding 2014 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;
- Case No. U-17678-R (direct), the Company's 2015 PSCR Reconciliation case, regarding 2015 RE Plan expenses recovered through PSCR;

- Case No. U-17918 (rebuttal), the Company's 2016 PSCR Plan and five-year forecast, regarding the impacts of net electric metering on energy supply;

- Case No. U-18081 (direct and revised), the Company's 2015 Renewable Reconciliation case, regarding 2015 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;

- Case No. U-18090 (direct, rebuttal, reopened rebuttal, second reopened rebuttal, affidavit, and third reopened rebuttal), the Company's 2016 Public Utilities Regulatory Policy Act case to establish a method and calculation for avoided costs;

- Case No. U-17918-R (direct), the Company's 2016 PSCR Reconciliation case, regarding 2016 RE Plan expenses recovered through PSCR;

- Case No. U-18241 (direct), the Company's 2016 RE Cost Reconciliation case, regarding 2016 RE Plan expenses recovered through PSCR;

- Case No. U-18402 (direct and rebuttal), the Company's 2018 PSCR Plan and five-year forecast, regarding long-term PPAs and capacity forecast;

- Case No. U-18231 (direct and rebuttal), the 2017 biennial review of the Company's RE Plan, regarding the Company's Request for Proposal ("RFP") process for new resources, the cost of new renewable energy resources included in the RE Plan, and the risks that may drive performance to vary, associated with these topics;

- Case No. U-18351 (rebuttal), the Company's 2017 Application to comply with Section 61 of 2016 PA 342, regarding customer credits in voluntary renewable energy programs and competitive solicitations;

- MPSC Case No. U-20165 (direct, rebuttal, and second rebuttal), the Company's 2018 Integrated Resource Plan ("IRP"), regarding long-term PPAs, proposed changes to the Company's Public Utility Regulatory Policies Act of 1978 ("PURPA") avoided cost implementation, the Company's proposal to utilize competitive solicitations and the implementation of the Financial Compensation Mechanism ("FCM");

- MPSC Case No. U-20219 (direct and rebuttal), the Company's 2019 PSCR Plan and five-year forecast, regarding long term PPAs and MISO revenue and expenses;

- MPSC Case No. U-20202 (direct), the Company's 2018 PSCR Plan and five-year forecast, regarding long-term PPAs and capacity forecast;

- MPSC Case No. U-20469 (affidavit), the Company's Application requesting an Order Rescinding Avoided Cost Rates, regarding the Company's avoided costs, obligations to enter new PPAs, and establishment of new avoided costs in the Company's IRP;

- MPSC Case No. U-20496 (direct), the Company's Application for approval of Amendments to the PPA with Viking Energy of Lincoln, LLC, Viking Energy of McBain, LLC, and Hillman Power Company;

- MPSC Case No. U-20604 (direct), the Company's Application for approval of PPAs with Commonwealth Power Company and North American Natural resources, Inc.;

- MPSC Case No. U-15805-S (affidavit), the Company's Application for approval of a renewable energy purchase agreement with River Fork Solar, LLC; and

- MPSC Case No. U-20525 (direct), the Company's 2020 PSCR Plan and five-year forecast, regarding long-term PPAs and the treatment of MISO revenue and expenses.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support: (i) PSCR costs expected to be incurred during the 12-month period from January 1, 2021 through December 31, 2021; (ii) the transmission cost analysis and impact of the Hemlock Semiconductor Operations, LLC ("HSC") Contract to PSCR costs; (iii) the Company's State Reliability Mechanism ("SRM") capacity methodology, cost offsets, and demand; (iv) the cost/benefit of continued investment in the reliability of the Company's generation assets; (v) the recovery of costs associated with an Independent Administrator ("IA"), the Company's FCM, and the solar solicitation as approved in the Company's IRP; (vi) stated benefits of the Company's Demand Response ("DR") programs; and (vii) Information Technology ("IT") projects to support Electric Supply operations.

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

A. Company witnesses Michael P. Kelly and Hubert W. Miller's direct testimony provides details and cost associated with the Hemlock Contract. Company witness Josnelly C. Aponte discusses SRM equations and how it fits in to cost of service. Company witness Scott A. Hugo describes the Company's generation asset investment plan. Company witness Heidi J. Myers' direct testimony discusses the accounting treatment for any required investment in the IRP solar initiative prior to the end of the projected test period ending December 31, 2021, and the proposed methodology for recovery of both the IRP-approved IA and FCM. Finally, Company witness Jeffrey D. Tolonen provides the accounting for the five IT projects listed in my direct testimony below.

Q. Have you prepared any exhibits in conjunction with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-109 (KGT-1)	2021 Power Supply Cost Recovery Forecast; and
Exhibit A-110 (KGT -2)	Financial Compensation Mechanism Forecast; and
Exhibit A-111 (KGT -3)	Forecast of Consumers Energy Transmission Expense.

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

A. Yes.

<u>POWER SUPPLY COST RECOVERY</u>

Q. Please explain Power Supply charges applicable to the Company's customers.

A. Power supply charges are applicable to the Company's full-service customers only. Full-service customers receive power supply service including generation and transmission costs, as well as, delivery service from the Company.

Q. Are Power Supply charges recoverable?

A. Yes. Power supply costs and expenses are recoverable, as detailed below.

Q. How are related costs and expenses recovered?

A. Power supply costs and expenses are reconciled in a filing before the Commission each year.

Q. Please explain how PSCR-related expenses are included in this filing.

A. The PSCR expenses are recovered monthly from full-service customers through a PSCR factor as discussed in the direct testimony of Company witness Eugene M. Breuring. A portion of the PSCR expenses related to the cost of capacity are utilized to calculate the SRM rate as discussed later in my direct testimony.

Q. Please explain Exhibit A-109 (KGT-1).

A. Exhibit A-109 (KGT-1) is a forecast of the Company's PSCR expenses and revenues summarized by projected energy supply source, quantity, and expense for the test year.

Q. How were the figures in Exhibit A-109 (KGT-1) derived?

A. The figures were derived from PROMOD IV, a program developed and licensed by Asea Brown Boveri that performs production cost simulations of the Company's generating resources, purchased power resources, and interchange power resources to meet projected customer electric demand requirements.

The primary inputs to PROMOD IV are projected system loads, unit heat rates, maintenance schedules, unit Random Outage Rates ("RORs"), fuel costs, unit net demonstrated capabilities, and Purchased and Interchange ("P&I") power availability and costs.

The primary outputs yield a monthly cost amount for: (i) each unit of energy in the system requirements; (ii) any variable expenses; (iii) capacity, fixed and purchased Non-Utility Generators ("NUGs") costs; as well as (iv) power supply costs, value of delivered energy, total expenses, and any revenue credits. This model is also used to develop the Company's presentation in its annual PSCR Plan cases.

Q. Please explain any difference between the 2021 forecast filed as part of the 2020 PSCR Plan filing and the forecast presented in this rate case filing.

A. Updated information for all main inputs mentioned was included in a January 2020 run of the PSCR model previously utilized in the 2020 PSCR plan case (Case No. U-20525). Changes include updated sales forecast, fuel pricing, generation outage schedule, and PPA forecast.

Q. Please detail the line items in Exhibit A-109 (KGT-1).

A. Total system requirements (expressed in units of MWh) for the test year 2021 are shown on page 1, line 13. A portion of the PSCR expense is recovered under the Long-term Industrial Load Rate ("LTILR") described later in my direct testimony.

The total annual fuel and variable purchased and net interchange PSCR expense, excluding any fixed energy and capacity expense, is shown on page 1, line 26 (expressed in units of thousands of dollars). This information was derived using production cost simulations as previously discussed.

Line 34 shows the projected Transmission expense that is expected to be recovered as part of the Company's power supply costs in PSCR proceedings. In Case No. U-14274, the Commission ordered that Transmission costs are to be included in the Company's PSCR Plan and Reconciliation filings. Line 36 shows a projected credit received from

MISO for generation-related reactive services. Lines 35 and 37 through 39 show reagent expenses for pollution control that are expected to be recovered as part of the Company's power supply costs in PSCR proceedings.

Lines 27 through 32 present the fixed and capacity-related costs included in PSCR expense, including the IRP Settlement Agreement-approved IA cost (Line 32), which is discussed in more detail later in my direct testimony.

The total PSCR costs are shown on page 1, line 40. The corresponding total PSCR expense recovered through the LTILR is shown on page 1, line 41 and the remaining PSCR expense to be recovered from full-service customers is shown on page 1, line 42.

Pages 2 and 3 of Exhibit A-109 (KGT-1) summarize the purchased and interchanged power quantity and corresponding expenses or revenues projected to be incurred by the Company in the 2021 test year. These pages detail the volume associated with purchases from NUGs and markets shown in the "Total Received" (Line 45), and deliveries shown "Total Delivered" (Line 49) categories shown on page 2 of Exhibit A-109 (KGT-1).

Q. Please explain how capacity is accounted for in Exhibit A-109 (KGT-1).

A. As discussed later in my direct testimony, the MISO has created a capacity market that utilizes Zonal Resource Credits ("ZRCs") as a capacity commodity. Some test year expense is the cost of capacity in the form of ZRCs purchased through bilateral agreements. For purchases already made, the actual price paid is allocated to each month for which the purchase applies. These expenses are shown on line 27 of Exhibit A-109 (KGT-1).

Q. What expenses are included in the PSCR calculations?

A. PSCR expenses include both fixed and variable expenses. Variable expenses include, but are not limited to, fuel expense, variable purchased energy, and MISO interchange, as well as a portion of the Company-owned facilities included in the Renewable Energy Plan, as shown on lines 14 through 26 of Exhibit A-109 (KGT-1). Fixed expenses include, but are not limited to, purchases of fixed energy and capacity, as well as, a portion of the Company-owned facilities included in the Renewable Energy Plan, as shown in lines 27 through 33 of Exhibit A-109 (KGT-1).

Q. Please explain the expenses for Company-owned resources included in the Renewable Energy Plan?

A. In general, for most Company-owned resources, there is no fixed expense included in PSCR expenses. However, the exception to this generalization[1] is presented on line 28 of Exhibit A-109 (KGT-1) where the Company-owned renewable capacity (or fixed-expense related) component of the transfer price associated with the Company's owned renewable resources is provided, complementing the energy (or Company-owned variable-expense related) component of the transfer price presented on line 18 of Exhibit A-109 (KGT-1).

Q. Please explain how PPAs are structured.

A. PPAs include both fixed and variable costs. Some PPAs define payments as "capacity" payments, "fixed energy" payments, and "variable energy" payments. Capacity payments and fixed energy payments are generally regarded as fixed expense because they are expected to be incurred regardless of the amount of energy delivered by the supplier.

[1] Fixed expenses related to transfer costs is an allowable cost included in PSCR cases under Public Act 295 of 2008, ("Act 295") the Clean and Renewable Energy and Energy Waste Reduction Act, enacted October 2008.

Variable energy payments generally reflect the cost of fuel and variable labor and thus vary depending on the amount of energy delivered.

Some other PPAs provide for a single price to be paid for each unit of energy to be delivered based on a capacity price and a combined fixed and variable energy price. Generally, these types of contracts are not dispatchable by the Company, thus the amount to be paid is likely limited by the physical capability of the supplying facility. In these instances, we have estimated the fixed energy costs based on the rates upon which the contracts were originally modeled.

Under Act 295[1], some other PPAs are included in the Company's rates based on the amount of cost allowed under state law to be transferred from the Company's Incremental Cost of Compliance to its PSCR costs through the transfer price mechanism. To estimate the amount of capacity, fixed energy, and variable energy expense associated with these transfer costs, the Company used the energy and capacity schedules approved by the Commission in Act 295 and through the Company's subsequent Renewable Energy Plan proceedings to determine the transfer expenses.

Energy or variable cost-related expense for the Company's PPAs (excluding the Palisades PPA) is shown on page 1, line 24 of Exhibit A-109 (KGT-1), labeled "Purchased (NUGs) Variable Cost." Capacity or fixed cost-related expense for the Company's PPAs (excluding the Palisades PPA) is shown on page 1, lines 30 and 31, labeled "Purchased (NUG) Capacity" and "Purchased (NUG) Fixed Energy" respectively. The variable and fixed expenses associated with the Palisades PPA are shown on lines 16 and 29 of Exhibit A-109 (KGT-1), respectively.

Q. What are the total expenses in the 2021 PSCR forecast?

A. The Company is forecasting $2,041,905,000[2] of PSCR expense expected to be incurred during the test year, including $742,330,000[3] of fixed expense, that is expected to be recovered from full-service customers and the LTILR Contract.

Q. Are the projected fuel expenses and the projected purchased and interchanged power expenses shown on Exhibit A-109 (KGT-1) subject to any uncertainty?

A. Yes. The expenses are based on projections made by the Company of fuel costs, customer demand, generating unit availability, P&I power availability, P&I power prices, inflation, and other factors that cannot be predicted with precision. It follows that any results from the use of these projections provide a reasonable but uncertain estimate of Power Supply costs.

Q. Please summarize your direct testimony regarding Power Supply charges.

A. The Company anticipates incurring approximately $2,041,905,000 in total PSCR expenses during the test year, of which $49,168,000 is expected to be recovered from the LTILR Contract, and $1,992,737,000 is expected to be recovered from other full-service customers during the test year.

<u>THE HSC CONTRACT</u>

Q. In the PSCR Exhibit A-109 (KGT-1) there is a line item for LTILR PSCR Payments. Please explain why this is specifically noted in the exhibit.

A. As detailed in Mr. Kelly's direct testimony, under Act 348, the Company entered into a contract for a LTILR with HSC in July 2019 (subject to MPSC approval before January

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[2] See Exhibit A-109 (KGT-1), page 1, line 40, column (o).
[3] See Exhibit A-109 (KGT-1), page 1, line 33, column (o).

2021) based on the cost of the Company-owned Zeeland combined cycle generating unit. Under Act 348[4], the approval of any contract for a LTILR is predicated on a net benefit to the electric utility's customers. Mr. Miller discusses the net benefit analysis related to the HSC Contract in his direct testimony.

Q. As required by Act 348, did the Company conduct a net benefit analysis of the HSC Contract?

A. Yes. As discussed in Mr. Miller's direct testimony, the Company conducted a net-benefit analysis, considering the customer benefit on the resulting cost of transmission for all remaining retail customers in two scenarios: (i) the HSC Contract is in place for long-term service from the Company; and (ii) HSC not purchasing standard tariff service from the Company.

Q. Please explain Exhibit A-111 (KGT-3).

A. Exhibit A-111 (KGT-3) details a forecast of the total transmission expense recovered from retail customers under each of these two scenarios. Column (b) shows the forecast expense under the first scenario which assumes that the HSC Contract is in place and the customer's load is served by the Company. Column (c) shows the forecast expense under the second scenario which assumes that HSC invests in its own generation and a portion of the interconnection costs are charged to the Company.

Q. How were the expenses in Exhibit A-111 (KGT-3) derived?

A. The figures were derived from the Company's transmission expense forecast model. The transmission charges included in the total transmission costs projected for 2021 and beyond

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[4] Act 348 http://www.legislature.mi.gov/(S(xnfr3rk0geweuul1bm5g3gfo))/mileg.aspx?page=getObject&objectName=mcl-460-10gg

are incurred as a result of the mandated expenses charged to Consumers Energy by MISO pursuant to numerous MISO rate schedules. This forecast includes projected costs related to transmission projects from the MISO Transmission Expansion Plan, along with all other Regional Transmission Operator administrative expenses associated with the MISO footprint.

Q. Please explain why this specific retail contract results in different transmission costs to customers under these two scenarios?

A. If HSC were to reduce its retail purchases from the Company by installing its own generation, the Michigan Electric Transmission Company ("METC") transmission revenue requirement would *remain the same*. Consequently, the Company would have avoided a portion of the assessed transmission costs, where those costs would have been reallocated to load serving entities served by METC. As shown in column (c) of Exhibit A-111 (KGT-3), if the customer were to invest in its own generation instead of receiving energy under the LTILR contract, the total transmission expense incurred by the Company would be reduced.

Q. Does this analysis conclude that other retail customers would benefit if HSC invests in its own generation?

A. No. This analysis only shows the total transmission costs that the Company forecasts under these two scenarios. As demonstrated by the net benefit analysis presented by Company witness Miller, other customers will experience a reduction in transmission expense if the LTILR contract is in place due to the amount of transmission expense recovered from HSC. Additional elements and conclusions of this forecast and the net benefit analysis are discussed in Mr. Miller's direct testimony.

Q. How will the LTILR contract effect the forecasting and reconciliation of PSCR expenses?

A. Under the LTILR contract, the contracting retail customer pays the entire cost of PSCR service, fuel and transportation costs, market energy purchases, transmission expenses, ancillary services, and aqueous ammonia based on the Zeeland combined cycle generating unit.

Q. How is this reflected in a PSCR plan and reconciliation?

A. Assuming the Commission's approval of the LTILR contract, beginning with the 2021 PSCR plan year, the Company will allocate a portion of the projected PSCR expenses and revenues directly related to, and recovered exclusively from, the LTILR customer. The remaining PSCR expense will be recovered from all other retail PSCR customers.

Q. Does this customer's participation in an interruptible service rate affect the Company's capacity obligations with MISO?

A. No. As discussed later in my direct testimony, the Company's Planning Reserve Margin Requirement ("PRMR") is established based on the load forecast provided to MISO for a given Planning Year. The Company will provide MISO with a load forecast that accounts for the amount of load reduction the customer can provide for the upcoming planning year. The Company will then be able to register this load reduction as a DR capacity resource for the upcoming planning year and receive ZRCs that can be utilized to meet the Company's PRMR. In summary, the amount of ZRCs received for the customer's load reduction capability can be used to offset any increase in the Company's PRMR associated with the same amount of load reduction that is incorporated in the forecast. The Company's remaining customers will be indifferent to the amount of load reduction capability from the customer.

SRM – CAPACITY CHARGE REVENUE OFFSETS AND DEMAND

Q. Please describe the SRM Capacity Charge.

A. In the Commission's November 21, 2017 Order in Case No. U-18239 ("November 21 Order"), the Commission adopted a methodology for determining the SRM Capacity Charge pursuant to Public Act 341 of 2016 ("Act 341"). The capacity charge "is a retail rate, designed to recover the incumbent utility's cost of providing capacity service, to whatever type of customer load – bundled or choice" (November 21 Order, page 73) to ensure long-term resource adequacy to customers in the State.

Q. How is the capacity charge determined?

A. Company witness Aponte's direct testimony describes in depth how the capacity charge is calculated and what inputs are utilized in the calculation. As discussed in Ms. Aponte's direct testimony, the SRM Capacity Charge calculation includes capacity offsets and the capacity charge demand (in ZRCs, converted to MW) used as the denominator of the capacity charge. These inputs rely on data that is detailed in my direct testimony below.

Q. Please define capacity offsets.

A. Capacity offsets are projected revenue(s) and associated fuel costs that are subtracted from any calculated capacity-related cost.

Q. Please identify the capacity offsets.

A. The capacity offsets used in this calculation are:

(i) Energy Market Sales of $853,446,000;

(ii) Off-System Energy Sales of $11,475,000;

(iii) Ancillary Service Sales of $12,128,000;

(iv) Bilateral Energy Sales of $0; less

(v) Related Fuel Costs of $480,460,000.

Q. What is the basis for the information presented in the prior answer?

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 2021 test year (sum of lines 1 through 7 and lines 9 and 11 in Exhibit A-109 (KGT-1)) multiplied by the Company's forecast of the average monthly locational marginal price.[5] The Off-System Energy Sales offset is based on the 2018 sales made to the Company's sole non-jurisdictional wholesale customer. The Ancillary Service Sales offset is based on the most recent-year value, in this case 2018. The Company made no bilateral energy sales in 2018 and does not forecast to make any bilateral energy sales in the test year. Related Fuel Costs are the forecasted fuel costs as extracted from the Company's forecast of power supply costs for the 2021 test year (sum of lines 14, 15, and 17 through 19 in Exhibit A-109 (KGT-1)).

Q. Do the fuel expenses shown on Exhibit A-109 (KGT-1) account for all Related Fuel Costs associated with Energy Market Sales?

A. No. The variable expenses associated with the volume of sales from PPAs are not included in the calculation of Related Fuel Costs presented above. While most generators incur a variable expense whether they are owned by the Company or owned by an independent power producer, under the methodology adopted by the Commission, the variable expense

[5] The Company's forecast of the average monthly locational marginal price is based on ARGUS forwards forecast dated October 29, 2019. The values for 2021 are as follows: January $32.750/MWh; February $30.750/MWh; March $28.050/MWh; April $25.700/MWh; May $24.850/MWh; June $25.050/MWh; July $28.550/MWh; August $26.450/MWh; September $24.550/MWh; October $24.200/MWh; November $24.750/MWh; December $27.200/MWh.

or fuel expense associated with generators owned by independent power producers are omitted for purposes of this calculation.

Q. What is the source for the capacity charge demand in ZRCs?

A. The capacity charge demand was established in the Company's December 2, 2019 Capacity Demonstration for Planning Years 2020 through 2023 filing in Case No. U-20590, Exhibit A-2, column (b), lines 1, 4, and 6.

Q. How is the capacity charge demand calculated?

A. The capacity charge demand value was determined as follows:

Line 1 – Forecasted Bundled (or Alternative Electric Supplier) Non-Coincident Peak Demand, MW	**7,906**
Line 4 – Load Diversity Factor coincident to MISO Factor %	**95.07%**
Line 1 * Line 4	**7,516**
* Line 6 – Transmission Losses, %	x **3.70%**
Consumers Energy load (including DR) coincident with MISO Peak, MW	**7,238**

Q. What is the source of the Consumers Energy load coincident with MISO?

A. The load coincident with MISO is sourced from the Company's PSCR forecast. This aligns with the calculation of the fixed costs identified by Company witness Aponte in the numerator of the SRM Capacity Charge.

Q. Why is the PSCR data used to provide this number?

A. PSCR data represents the amount of ZRCs assigned to the Company's capacity resources by MISO under its Resource Adequacy Construct.

Q. How does a ZRC relate to a MW for the purpose of calculating this number.

A. Under MISO's Resource Adequacy Construct, one ZRC is sufficient to serve one MW of demand.

Q. Please explain the basis for using the ZRC value assigned to the Company's capacity resources in the denominator of the SRM Capacity Charge.

A. The Company proposes to use ZRC values because it is the amount MISO assigns to, and accepts from, the Company's resources for purposes of satisfying its capacity obligation, also known as its PRMR.

Q. Could there be other sources for the Company's load coincident with MISO information?

A. In Case No. U-18239, it was proposed that this data be sourced from the Company's most recent Securities and Exchange Commission ("SEC") Form 10-K filing.

Q. Why does the Company not utilize the SEC Form 10-K filing information?

A. Use of a historical value from the SEC Form 10-K filing is not appropriate since it does not accurately represent the Company's plans for the test year that is the subject of this proceeding.

Q. Did the Company file a case for a review of the SRM Capacity Charge by April 1, 2019?

A. No. In the November 21 Order, the Commission directed the Company to file a standalone contested case for the annual review of the SRM Capacity Charge by April 1, unless the Company expects that the annual review will take place in a rate case or PSCR case that will conclude by December 1 of each year.

On April 1, 2019, the Company notified the Commission via Case No. U-18239 that the Company proposed in its 2018 PSCR Reconciliation proceeding, Case No. U-20202, that the SRM Capacity Charge approved in Case No. U-20134 remain in effect for Planning Year 2020/2021. In its notification to the Commission, the Company also indicated no reconciliation of forecasted versus actual amounts, under MCL 460.6w(3)(b), is necessary because no Alternative Electric Supplier customers were assessed the SRM Capacity Charge in 2018.

Q. Does the Company expect the same to hold true in 2020?

A. Yes. The Company has not yet assessed an SRM charge and expects to inform the Commission of that on April 1, 2020, unless circumstances change.

CONTINUED RELIABILITY INVESTMENT

Q. Can the Company quantify the benefit of the proposed investments in its units?

A. Yes. Company witness Hugo provides a comprehensive description of Net Energy Value ("NEV"), which the Company utilizes to analyze and quantify a generation asset's benefit to the Company's customer on an energy basis.

Q. In his direct testimony, Mr. Hugo proposes $17,989,000 in capital investments to maintain the capacity value of Karn Units 3 and 4, including the $2,300,000 in capital for project "Karn 4 EHC retrofit" in the 2020 bridge year. Why is the continued and/or improved capacity from the Company's assets important for the Company's customers?

A. As discussed by Mr. Hugo, reliability investments are expected to improve the ROR at generating units. Improvements in ROR are expected to produce a corresponding improvement in the Equivalent Demand Forced Outage Rate ("EFORd") for those generating units. Improvement in EFORd translates into increased capacity credit received from MISO in the form of ZRCs. The increased capacity credit is part of the Company's plans for meeting future PRMR and avoids the need to purchase ZRCs.

Q. Please explain what PRMR is and how it relates to ZRCs.

A. The PRMR is the amount of capacity that a Load Serving Entity ("LSE") (such as Consumers Energy) maintains to assure that sufficient capacity exists to provide adequate electric supply in each Planning Year ("PY") period. MISO's PY begins on June 1st of each year and concludes on May 31st of the following calendar year. The Company relies on MISO to determine the appropriate PRMR that Consumers Energy should maintain. The PRMR is calculated by MISO using (i) the Company's forecast peak load coincident to MISO's peak, (ii) a transmission loss percentage applicable to the Company, and (iii) a reserve margin to ensure reliability.

To facilitate compliance with the planning reserve margin target, MISO has established ZRCs as a measure of a resource's available capacity commodity. One ZRC of capacity is expected to be sufficient to serve one MW of forecasted demand, providing an appropriate discount for generator forced outages or effective load carrying capability. ZRCs eliminate the potential for double-counting MISO market participants' resources within the MISO market footprint through tariff requirements on market participants to use the Module E Capacity Tracking tool.

Q. Please explain how ZRCs are calculated for the Company's generation assets?

A. Each generator owned by the Company that is interconnected to the transmission system has an interconnection service limit. For non-intermittent generators, the Company submits an annual test, including any applicable test normalization, to determine the Generator Verification Test Capacity ("GVTC") of the generator.

Over each three-year period, startup, run time, and outage information is collected and categorized to determine the EFORd value for each generator. Prior to each Planning

Year, MISO awards ZRCs to generator owners based on the lesser of the interconnection service limit and the GVTC, multiplied by the result of one minus EFORd.

Q. What is the ultimate effect of obtaining ZRCs on generating units?

A. The Company's sustained capital investment in generator reliability allows the Company to improve the EFORd of its units and, as a result, increase the amount of ZRCs that will be provided to a generation resource. These ZRCs are a key component of meeting the Company's PRMR and mitigating customer exposure to capacity price risk from having insufficient capacity resources to meet the Company's PRMR.

Q. Please describe the EFORd improvement that will result from the identified capital investments.

A. As described above, EFORd is based on a three-year average of asset operating data. Therefore, any new capital investments which increase unit reliability improve the sample of operation data that is utilized to determine the EFORd. Investing in reliability now ensures that improvements in ZRCs and the corresponding value to customers are realized in the future.

Q. Please describe the result if no additional investments are made.

A. If no additional investments are made, the deterioration of a plant's EFORd is expected to increase over time, reducing the capacity value of the facility.

Q. What would be the result of the deterioration of EFORd?

A. On an energy basis, EFORd increases (deteriorates) as a result of poor operational performance. Therefore, deterioration of EFORd also means a reduction in the overall NEV for the Company's customers. On a capacity basis, the possibility of having to purchase replacement capacity to meet the Company's PRMR could result in a significantly higher price of capacity for all customers throughout MISO Zone 7 by driving the MISO auction clearing price for capacity to the Cost of New Entry ("CONE"). Lastly, a deterioration in EFORd is an indication of poor reliability, meaning an increased risk in system reliability for MISO Zone 7.

Q. Please explain the concept of CONE.

A. CONE is an industry-wide concept that represents the capital cost of constructing a new source of power to provide capacity. MISO uses CONE to establish the maximum clearing price for MISO's capacity market as established in the Planning Resource Auction ("PRA").

Q. At what cost has the CONE been set in recent years?

A. For the planning year 2018/2019, the CONE was \$248.60/ZRC-day. CONE for planning year 2019/2020 has been set at \$243.37/ZRC-day.

Q. For comparison, what was the clearing price for capacity in MISO Zone 7 for each of the above PYs?

A. Zone 7 cleared at \$10/ZRC-day in the planning year 2018/2019, and \$24.30/ZRC-day for the planning year 2019/2020.

Q. Please explain how the capacity market clearing price is set for MISO Zone 7.

A. There are several factors that go into setting the MISO capacity market clearing price. MISO details the capacity market construct in Business Practice Manual 11: Resource Adequacy[6]. To summarize the construct, each Market Participant that holds ZRCs can offer them into the annual PRA. Market Participants receive capacity awards from lowest cost to highest cost until the PRMR for all the LSEs is met. The highest price to receive

[6] https://www.misoenergy.org/legal/business-practice-manuals/

an award sets the clearing price that is paid to all other capacity awards on a $/ZRC-day basis, which is called the Auction Clearing Price.

Individual MISO Zones can have different Auction Clearing Prices in the capacity market. In planning year 2019/2020, MISO Zone 7 was $24.30/ZRC-day while all other Zones cleared at $2.99/ZRC-day. Zones are limited on the amount of capacity that can be imported to or exported from the Zone. Additionally, individual Zones have a local clearing requirement which establishes how much capacity from the Zone must be used to meet PRMR within the Zone. It was this local clearing requirement that established price separation for Zone 7 in planning year 2019/2020. This result shows that if there is not enough capacity in Zone 7 to meet the local clearing requirement, the Zone will experience price separation up to the point that CONE is reached, unless more capacity (or less PRMR) is made available in the Zone.

Q. If the cost of capacity were to go to CONE, how would the Company's capacity position be affected?

A. If MISO Zone 7 clears at CONE, it is a signal that the Zone does not have enough capacity to meet either the Zone's local clearing requirement or PRMR, which, in turn, means that there is an increased risk of system-wide reliability issues. Also, in the event that the Company is a net purchaser of capacity, an Auction Clearing Price of CONE would result in significant price increases to the Company's customers. MISO's planning year 2019/2020 results[7] show that 22,063.2 ZRCs were offered from Zone 7 and 21,811.6 ZRCs cleared resulting in an offered capacity of only 251.6 ZRCs of surplus capacity in Zone 7 or 1.1% of the local clearing requirement.

[7] https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf

Furthermore, it should be noted that, within the SRM construct, the Company may only purchase 5% of its projected PRMR in the PRA. If reliability issues result in a capacity need greater than 5%, the Company would have to consider a significant financial commitment to build new capacity. In contrast, investment in already-existing capacity resources provides a more cost-effective benefit.

Q. What conclusion have you reached relative to the investment being sponsored by Mr. Hugo?

A. Mr. Hugo details the current capacity value of Karn Units 3 and 4 in his direct testimony, based upon both settlement prices and CONE for ZONE 7. The proposed reliability investments produce reserve capacity value that exceeds the capital expenditures necessary to achieve the value. Consequently, Consumers Energy's customers will benefit from the investment into these assets via increased capacity and the avoidance of purchasing capacity from the market. Additionally, the loss of either Karn Unit 3 or Karn Unit 4 from the capacity market would have resulted in an auction clearing price equal to CONE in the planning year 2019/2020. For the reliability of the Zone and stability of capacity market prices, it is pertinent to ensure that reliability of Karn Unit 3 and Karn Unit 4 are maintained in the coming years.

FINANCIAL COMPENSATION MECHANISM

Q. Are you familiar with the Company's FCM?

A. Yes. The FCM was approved as part of the IRP Settlement Agreement in Case No. U-20165 (the "IRP Settlement"). The FCM, as described in Paragraph 9 of the IRP Settlement, and allows the Company to receive, and recover in general electric rates, an

FCM on all new PPAs, excluding any PPAs executed under the Company's Renewable Energy Plan, approved by the Commission on or after January 1, 2019.

Q. What considerations were given for the FCM in the IRP Settlement?

A. For PPAs eligible for the FCM, the Company will be authorized to annually earn the FCM equal to the product of PPA payments in that year, multiplied by the Weighted Average Cost of Capital ("WACC") in affect at the time of contract execution. However, the FCM shall not exceed the WACC of the Company's total capital structure multiplied by the schedule of MWh prices in Attachment B to the IRP Settlement based upon the time of the PPA execution.

Q. Does the FCM follow a calendar year?

A. Yes. Company witness Meyers details the Company's proposed methodology for recovery of the FCM which includes a reconciliation of projected FCM expenses to actual FCM recognized. Since the FCM is expected to be reconciled on an annual basis, the Company proposes to limit the FCM on an annual basis. The FCM period for each calendar year starts January 1 and concludes December 31.

Q. Does the Company treat similarly capped expenses on an annual, instead of monthly, basis?

A. Yes, the amount of expense recovered through the PSCR via the transfer price for RE Plan projects is similarly capped on an annual basis.

Q. Was a methodology for recovery agreed to in the IRP Settlement?

A. No. The methodology for recovery was directed to be determined in the Company's next electric rate case.

Q. Has the company executed any PPAs that will be eligible for an FCM?

A. Yes. The Company has negotiated and executed numerous contracts subject to the FCM at the time of this filing. The Company forecasts that additional PPAs will be executed that result in deliveries and FCM-eligible expenses included in the 2021 test year. Please reference Exhibit A-110 (KGT-2) for a list of expected FCM-eligible PPAs and the forecast FCM expenses included in this filing.

IRP COMPETATIVE SOLICITATIONS AND INDEPENDENT ADMINISTRATOR

Q. Please explain the Company's IRP competitive solicitation process.

A. The Company's competitive solicitation process for procurement of new supply-side resources was approved in the IRP Settlement. The solicitation process is applicable to the procurement of future supply-side capacity additions in the Company's annual IRP solicitations. The Company's PCA includes the procurement of 300 MW of solar in 2019, 300 MW of solar in 2020, and 500 MW of solar in 2021 for facilities that will enter service in 2022, 2023, and 2024, respectively.

Q. How was the competitive solicitation established?

A. As explained above, the competitive solicitation process was approved in the IRP agreement (see Paragraph 7 of IRP Settlement) for selecting any new supply-side capacity resources. The resulting cost of the new capacity resources from this competitive solicitation process will be used as the basis for determining future avoided costs available to Qualifying Facilities, in accordance with PURPA, based on the highest cost selected proposal to receive a contract as part of the competitive solicitation.

Q. How does the process work?

A. The competitive solicitation process includes: (i) an agreement that at least 50% of the new capacity will be procured through PPAs (the Company may select more than 50% PPAs at its discretion); and (ii) the Company will utilize an IA to conduct the solicitation, complete the proposal evaluations, and provide a blind ranking of projects to the Company for selection.

Q. Please describe how the IRP Settlement directed the competitive solicitations to be structured.

A. As described in the IRP Settlement, the Company follows the same process utilized in its RE Plan solicitations, with some modification as outlined in Attachment A to the IRP Settlement.

The IRP-specific solicitations are administered on an annual basis. The criteria for solicitations are to be made clear to all parties, in part by sharing at a series of stakeholder meetings with stakeholders having opportunities to file comments on the reasonableness of the evaluation criteria. As mentioned above, the process is administered by an IA, who reviews and ranks the proposals, providing them to the Company for consideration.

Q. Does the Company plan to increase its solar capacity via the competitive solicitation process?

A. Yes. The Company's planned increases in solar capacity are detailed in the PCA approved in the IRP, which included the addition of 1,200 MW of solar energy resources by 2024. The first 100 MW of incremental solar energy resources will support the Company's RE Plan, leaving a balance of the 1,100 MW of solar energy capacity available for competitive solicitations.

Q. How does the Company plan to implement the solar capacity?

A. All new solar capacity additions included in the IRP will be procured through competitive solicitations including both PPAs and Company-owned projects. As previously discussed, at least 50% of the new capacity will be purchased through PPAs, and the remaining capacity is expected to come from Company-owned facilities. Under the 50% Company ownership, the Company plans to add 150 MW of solar in 2022, 150 MW of solar in 2023 and another 250 MW of solar in 2024.

Q. Has the Company begun administering the competitive solicitations for new solar capacity?

A. Yes. The first steps in establishing the competitive solicitations under the IRP included the selection of the IA and the first of two stakeholder meetings in August 2019. The IA issued an RFP on behalf of the Company on September 30, 2019. Review and evaluation of proposals were completed by the IA in November 2019, and the selection process was completed by the Company in December 2019. The Company is currently negotiating final agreements and anticipates executing agreements in 2020. Company witness Hugo discusses the timing and level of investment the Company anticipates for Company-owned projects that are selected as a result of the IRP competitive solicitation process.

Q. Please explain how the expense associated with the services performed by the IA will be recovered.

A. Paragraph 7(c) of the IRP Settlement required the use of an independent third party to administer competitive bids related to the PCA approved in the IRP. The IRP Settlement also detailed the roles and responsibilities of the IA but did not specify which cost recovery mechanism should be utilized to recover the expense associated with the IA's service agreement. As discussed in the Company's 2020 PSCR Plan filed in Case No. U-20525, the Company believes that the costs related to the service agreement with the IA should be recovered through the PSCR.

Q. What are the estimated expenses for the IA?

A. The expenses for the IA are projected to be $200k per year as shown on line 32, of Exhibit A-109 (KGT-1).

Q. Has the Company included the cost of services for the IA in any other proceedings?

A. Yes. The Company included the cost associated with the service agreement with the IA in its 2020 PSCR Plan, Case No. U-20525. As discussed in that proceeding, at least 50% of the selected projects will be PPAs and the solicitation will result in the purchase of capacity recoverable via PSCR cases. However, in the event that the Commission determines that these IA expenses are not recoverable through the PSCR, the expenses should be recovered as an O&M expense through this electric rate case proceeding.

Q. What costs were requested in Case No. U-20525?

A. IA costs for a portion of the 2019, and 2020 solicitation years were requested for approval as a 2020 expense. The Company forecast in that proceeding that the annual IA expenses would continue through the 5-year period addressed in the 2020 PSCR Plan. In addition to that forecast, the Company expects to continue to incur IA expenses during the implementation of the PCA approved in the IRP which covers a 15-year period (see Paragraph 1 of the IRP Settlement).

Q. Is the Company proposing to recover the cost of IA services this rate case?

A. As discussed above, the Company has proposed recovery of IA expenses through the PSCR mechanism. However, if the Commission does not approve the cost for the IA in the

Company's 2020 PSCR Plan, Case No. U-20525, and subsequently in the PSCR reconciliation proceedings, the Company requests approval in electric rates in the form of O&M expenses.

DEMAND RESPONSE PROGRAMS

Q. Please explain the types of DR programs expected to be employed by the Company in 2021.

A. The Company's DR programs planned for 2021 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 that are 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 that is driven by rate structures that incentivize customers to use less energy during peak periods.

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 2021/2022?

A. For Planning Year 2021/2022, the Company will administer five DR programs that are controlled by the Company, including the Residential Air Conditioning Peak Cycling Program at 75 MW (85 ZRCs), Bring Your Own Device ("BYOD")—a new DR program at 15 MW (17 ZRCs), Commercial & Industrial ("C&I") Emergency DR at 240 MW (271 ZRCs), Energy Intensive Program Rate ("Rate EIP") at 96 MW (109 ZRCs), and Interruptible Service Provision ("Rate GI") at 103 MW (116 ZRCs).

Also, for Planning Year 2021/2022, the Company will offer DR programs that are dependent upon customer behavior; including the Residential Critical Peak Time-of-Use and Peak Rewards Time-of-Use programs at a 16 MW (16 ZRCs) as well as the Residential Summer Time of Use standard rate at 119.4 MW (123.6 ZRC).

Q. What is the approximate market value of these DR resources?

A. Consumers Energy's 2021 DR portfolio is projected to total 665 MW (738 ZRCs), valued at $53 million at an estimated value of capacity at $71,910/ZRC-Year.[8]

INFORMATION TECHNOLOGY

Q. Is the Company planning technology projects that support the Electric Supply section of Electric Grid Integration?

A. Yes. Company witness Tolonen includes in his direct testimony and exhibits, several technology projects that are critically important to support the electric business in a safe, effective, efficient, and compliant manner. These projects are described below:

- The **Centralized DR Management Assessment** project requires $305,700 in O&M in the test year. This project is intended to explore feasibility and options to centralize control for initiating, managing, and reporting of all events for DR programs and pilots. This project will provide clear understanding of the requirements needed to enable the Demand Response Management System ("DRMS") to support the significant growth in DR capacity as outlined in the Company's IRP. This effort will be completed prior to making a large investment in modifying or replacing the current DRMS technology. The scope for this assessment includes: (1) evaluating moving to a cloud solution; (2) fully vetting integration requirements for all proposed DR programs; (3) reviewing the backlog of requested enhancements to DRMS; (4) evaluating alternate DR solutions; (5) identifying opportunities to leverage additional functionality of

[8] Based on 75% of MISO's Planning Year 2020/2021, Cost of New Entry escalated by 2% to reflect Planning Year 2021/2022.

current DRMS; (6) mapping DRMS features to requirements needed to support additional DR programs and the IRP; (7) documenting and reviewing current state and future state DR organization and processes to achieve centralized DR operated from one operations center; and (8) mapping future state for DRMS where it integrates with the Distributed Energy Resource Management Solution ("DERMS").

  - Alternatives to be considered during this assessment include: (1) continuing to maintain the current hardware and software at the risk of continued inability to centralize information for all DR programs, (2) enhancing the existing solution to address centralization needs, (3) transitioning the application to the vendor's hosted environment and configure to address requirements for additional DR programs, (4) replacing the current solution with a new cloud solution, and (5) replacing the current solution with a new internally hosted solution. Due to the significant increase in DR capacity as outlined in the IRP, further assessment of the technology requirements is needed.

- The **Centralized DR Management** project requires $1,293,000 in capital and $127,000 in O&M in the test year. This project is intended to centralize initiation and reporting of all DR event activities into one technical solution and will be informed by the outcomes of the Centralized DR Management Assessment effort described above. The project will add value by providing functionality to ensure DR events can be collectively managed from a central solution that includes all programs and potential load shed. The upgraded DRMS application, included with the Centralized DR Management project, will be able to support the various DR Programs including new Electric Charging Vehicle programs and Time-of-Use ("TOU") rates implemented in 2020. Finally, this upgraded application will ensure accuracy of kilowatt hour (kWh) savings and peak load reduction when a DR event is called. The scope consists of: (1) centralization of the DR event management programs including residential DR, bring your own device, electric vehicle charging and large customer DR; (2) upgrade or replacement of the DRMS with a potential move to a cloud-based solution; (3) provision of new DRMS system functionality to support on-going DR programs; and (4) addition of DRMS functionality to account for the new TOU rates.
  - Alternatives considered during the assessment effort include: (1) continue to maintain the current hardware and software at the risk of continued inability to centralize information for all DR programs; (2) enhance the existing solution to address centralization needs; (3) transition the application to the vendor's hosted environment and configure to address requirements for additional DR programs; and (4) replace the current solution with a new cloud solution; or (5) replace the current solution with a new internally hosted solution. The selected alternative will be made as an outcome of the Centralized DR Management Assessment effort.

- The **MISO Market User Interface ("MUI") Changes** project requires $65,000 in capital and $68,000 in O&M in the test year. This project will update the Power Costs Inc. ("PCI") software used for market interaction and settlements with MISO. These changes are required as a result of significant MISO redesign of the MUI to modernize technology and improve cyber security. The project will provide benefits to the Company by meeting required changes to the MUI initiated by MISO, modernizing technology and improving cyber security. This is a significant change that requires updates to the PCI software used for market interaction and settlements with MISO. These updates will be applied incrementally as MISO and PCI release the updates. Each update requires installation in the test environment, regression testing, and user acceptance testing prior to implementation in production.
    - Alternatives considered in order to continue to interact with MISO include: (1) replacing PCI with a new product; or (2) updating the PCI solution. The alternative to replace PCI would require significant investment in research, product evaluation, people resources, and financial investment. Due to the schedule for updates provided by MISO, and the significant footprint of the PCI solution, the alternative to upgrade was selected.

- The **Electric Interconnection Billing and Payment** project requires $1,095,000 in capital and $148,000 in O&M in the test year. Entities with a desire to interconnect to the Company's electric distribution network are required to submit applications and associated fees for processing. This project will research, evaluate, and implement a solution that will provide for the electronic processing of applicant fees. Providing the capability for interconnection applicants to pay application fees electronically adds value through: (1) reduced manual internal processing of checks; (2) minimized risks associated with lost payments; and (3) increased likelihood in applicant satisfaction. The scope of this project includes: (1) researching industry solutions and defining requirements; (2) creating an RFP; (3) evaluating options and selecting a solution; and (4) designing and implementing the solution.
    - The alternatives considered include: (1) implement an electronic billing and payment solution that the Company's current interconnection solution provider integrated into their solution for another client; (2) implement electronic billing and payment functionality that is currently used to process other types of payments to the Company; and (3) delay implementation of a solution until accepting electronic payments becomes a regulatory requirement. The third alternative was not selected because risks associated with handling physical checks will continue, while providing less time for solution evaluation and implementation once processing of electronic payments becomes a regulatory requirement. Alternatives one and two, both cloud-based solutions, will be evaluated once requirements are finalized.

- The **MISO Market System Replacement** project requires $440,000 in capital and $66,000 in O&M in the test year. This project will implement software changes to in response to the announcement that MISO has determined that its current market system will be obsolete in five to seven years given evolving cyber security standards and increasing market complexity. To address these concerns, MISO is proposing a $134 million, seven-year incremental (modular) replacement to transition to a new market platform. This project adds value by implementing software changes in response to MISO's system changes to ensure the Company can participate in the MISO market. Project scope includes significant change requiring updates to the PCI software used for market interaction and settlements with MISO. These updates will be applied incrementally as MISO and PCI release the updates.
    - Alternatives considered in order to continue to interact with MISO include: (1) replacing PCI with a new product, or (2) updating the PCI solution. The alternative to replace PCI would require significant investment in research, product evaluation, people resources, and financial investment. Due to the schedule for updates provided by MISO, and the significant footprint of the PCI solution, the alternative to upgrade was selected.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

A. My name is Brian J. VanBlarcum, and my address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

A. I am a Tax Director in the Company's Corporate Tax Department.

Q. Please briefly describe your educational background.

A. I am a graduate of Western Michigan University where I earned a Bachelor of Business Administration degree in Finance.

Q. Please describe your business experience.

A. I started with the Company in 2004 as a General Accounting Analyst with the Company's property accounting team. In 2019, I was appointed to my current position as Tax Director with the Company's Corporate Tax Department.

Q. Are you a certified assessor?

A. I am a Michigan Certified Assessing Officer certified by the State of Michigan's State Tax Commission and a member of the Michigan Assessors Association.

Q. What are your responsibilities as Tax Director?

A. I am responsible for the administration of the Company's real and personal property taxes. This includes: (i) managing the Company's self-declaration of personal property located within the state of Michigan; (ii) overseeing property tax matters concerning the Company's land, generating sites, and other real property; and (iii) supervising tax payments to approximately 1,500 taxing authorities. I am also responsible for the calculation of federal and state tax depreciation related to the Company's fixed assets and the associated deferred income taxes.

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

A. Yes, I sponsored testimony in the following cases:

- Gas Rate Case No. U-15506;
- Electric Rate Case No. U-15645;
- Electric Rate Case No. U-16191;
- Gas Rate Case No. U-16418;
- Electric Rate Case No. U-17087;
- Electric Rate Case No. U-17735;
- Gas Rate Case No. U-17882;
- Electric Rate Case No. U-17990;
- Gas Rate Case No. U-18124;
- Electric Rate Case No. U-18322;
- Gas Rate Case No. U-18424;
- Electric Rate Case No. U-20134;
- Gas Rate Case No. U-20322; and
- Gas Rate Case No. U-20650.

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 December 31, 2021) 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 ("TCJA") and the Commission's September 26, 2019 Order in the Company's Calculation C Case No. U-20309.

Q. Have you prepared any exhibits to accompany your direct testimony?

A. Yes. I am sponsoring:

Exhibit A-112 (BJV-1)	Development of the Property Tax Rate for the Test Year; and
Exhibit A-113 (BJV-2)	Amortization of Excess Deferred Federal Income Taxes for the Test Year.

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

A. Yes.

<u>**Development of the Property Tax Rate for the Test Year**</u>

Q. What is the Property Tax Rate for the test year?

A. As indicated on Exhibit A-112 (BJV-1), page 1, line 14, the Property Tax Rate for the test year is 0.011851110.

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 Electric Property Tax Expense – 2021 (Exhibit A-112 (BJV-1), page 1, line 8 divided by the total of the 2020 Estimated Year-End Plant-in-Service (Exhibit A-112 (BJV-1), page 1, line 9 plus one-half of the 2020 Estimated Construction Work-in-Progress (Exhibit A-112 (BJV-1), page 1, line 12.

Q. What is included in the Electric Property Taxes Paid – 2020 Estimate on Exhibit A-112 (BJV-1), page 1, line 1?

A. The Consumers Energy 2020 taxes paid of $191.7 million on behalf of the electric portion of the business represents estimated property taxes to be paid in 2020.

Q. What is included in the Electric Property Taxes on 2020 Plant Investment on Exhibit A-112 (BJV-1), page 1, line 2?

A. The $14.4 million increase is the estimated property taxes on the 2020 net additions that will be included in the 2021 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 49.1226 to obtain the estimated tax amount. This calculation is shown on Exhibit A-112 (BJV-1), page 2, line 9.

Q. What is included in the 2021 Coal Plant Valuation Tax Reduction on Exhibit A-112 (BJV-1), page 1, line 3?

A. The $1.0 million decrease reflects a reduction in property taxes associated with the J.H. Campbell Plant (Units 1-3) and the D.E. Karn Plant (Units 1-2). The reduction in property taxes is the result of successful property tax litigation and negotiations with the local units of government over the taxable value of the Company's coal-fired electric generating facilities.

Q. What is included in the Electirc Property Taxes on Real Property Taxable Value Increases – Inflation on Exhibit A-112 (BJV-1), page 1, line 4?

A. The $1.0 million increase for the Real Property Taxable Value relates to the Michigan Constitution of 1963, Article IX, Section 3, allowing local assessors to raise real property taxable values by the lesser of 5% or the Consumer Price Index ("CPI"). For 2021, our property tax model assumes a CPI rate of 2.2%. This calculation is shown on Exhibit A-112 (BJV-1), page 3.

Q. What is the result of including the Electric Property Taxes on 2020 Plant Investment, 2021 Coal Plant Valuation Tax Reduction, and the Electric Property Taxes on Real Property Taxable Value Increase on the estimated 2021 property tax amount paid by the electric business?

A. The result of including these additional items is an estimated 2021 property tax amount to be paid for the electric business of $206.1 million as shown on Exhibit A-112 (BJV-1), page 1, line 5.

Q. Does the amount on Exhibit A-112 (BJV-1), page 1, line 5, include property tax payments for pollution control equipment or computer software, such as SAP?

A. No, as pollution control equipment and computer software are exempt under MCL 324.5904(1) and MCL 211.9d, the estimate of 2021 property tax to be paid on line 5 does not include property taxes associated with these items.

Q. How is this paid amount converted to an expense amount?

A. Since the Company expenses property taxes based on the fiscal year of the taxing authorities, 50.2% of the 2020 estimated electric property tax payments for Consumers Energy is added to the 2021 estimated electric payments since that amount will be expensed in 2021, while subtracting 50.2% of the 2021 estimated electric payments that will be expensed in 2022, arriving at a total 2021 electric property tax expense of $198.8 million as shown on Exhibit A-112 (BJV-1), page 1, line 8.

Q. What is the next step in calculating the tax rate for the test year?

A. The Electric Property Tax Expense for the test year is divided by the 2020 Estimated Year-End Plant-in-Service plus one-half of 2020 Estimated Construction Work-in-Progress to arrive at a property tax rate of 0.011851110.

<u>Amortization of Excess Deferred Federal Income Taxes for the Test Year</u>

Q. On September 26, 2019, the Commission issued an Order in the Company's Calculation C Case No. U-20309. What specific issues did the September 26, 2019 Order in Case No. U-20309 address?

A. The Commission's September 26, 2019 Order in the Company's Calculation C Case No. U-20309 authorized the amount and time period under which the Company will refund to electric customers $1,174,181,000 of excess deferred federal income taxes as a result of the TCJA lowering the corporate income tax rate from 35% to 21%. The Commission authorized three different amortization periods: (i) Protected plant balances over an amortization period determined using the Average Rate Assumption Method ("ARAM"); (ii) Non-Protected plant balances amortized over 27 years; and (iii) Unprotected non-plant balances amortized over 10 years. Exhibit A-113 (BJV-2), page 2, referenced as Exhibit A-5 (SBM-3) in Case No. U-20309, provides the projected annual amortization of these balances based on the periods approved by the Commission.

Q. Based on the Commission's September 26, 2019 Order in Case No. U-20309, what amount of excess deferred federal income tax has the Company proposed to return to customers in this case?

A. Exhibit A-113 (BJV-2), page 1 provides a calculation of the test year excess deferred federal income taxes included in this case based on the periods approved by the

Commission in Case No. U-20309. Overall, the Company reduced Federal Income Tax Expense for the test year by $26.658 million to reflect the amortization periods discussed above. This amount is shown on Company witness Heidi J. Myers' Exhibit A-13 (HJM-56), Schedule C-8, lines 46 and 47 as TCJA Amortization – ARAM and TCJA – Non ARAM.

Q. Are the excess deferred federal income tax amounts refunded to electric customers in the test year estimates or actuals?

A. The amounts included in this case are estimates as the Commission's September 26, 2019 Order in Case No. U-20309 requires an annual reconciliation of the actual amount of excess deferred federal income tax in a given year and the estimated amount included in rates. The Company will file this reconciliation in the Case No. U-20309 docket by March 31st of each year.

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	)	Case No. U-20697
the generation and distribution of	)	
electricity and for other relief.	)	
	)	

DIRECT TESTIMONY

OF

TODD A. WEHNER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

February 2020

Q. Please state your name and business address.

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

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Corporate Finance.

Q. What are your current responsibilities?

A. I am responsible for planning and raising the financial capital required by the Company including revolving credit facilities, short-term and long-term debt capital, and equity capital. As part of my role, I work with my treasury colleagues to manage corporate liquidity, financing, and treasury operations, and maintain relationships with the banking community, rating agencies, investors, and research analysts. In order to carry out my responsibilities, I interact with commercial banks, investment banks, credit rating agencies, equity and fixed income analysts, and equity and fixed income investors. I also play a key role in the Company's strategic planning process and in developing the Company's financial plan that fulfills its strategic goals.

Q. What is your educational background?

A. I received Bachelor of Science degrees in Electrical Engineering and Mechanical Engineering from Michigan Technological University in 2002. I received a Master of Business Administration degree ("MBA") from the Ross School of Business at the University of Michigan in 2012, where I focused on finance and strategy. Concurrently, I completed a Master of Science degree from the School of Natural Resources at the University of Michigan.

Q. What positions did you hold prior to your present position?

A. I began my career in 2002 as an Acquisitions and Maintenance Officer in the United States Air Force where I worked with intelligence units through 2006. I was an Electrical Test Engineer with Nissan from 2007 to 2009. After completing my MBA in 2012, I joined Barclays Capital as an associate in the Investment Banking Division focused on the chemicals sector. In this role, I developed financial models to value both public and private companies, executed merger and acquisition transactions, and executed financing transactions for companies across a number of markets including equity, investment grade debt, and high yield debt. I developed cost of capital analyses, rating agency materials, and strategic review materials for management and boards. In 2014, I joined Morgan Stanley and continued work as an associate and later as a vice president within the Investment Banking Division, focused on the power and utilities sector. In early 2016, I joined Consumers Energy as Director of Corporate Finance.

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

A. Yes. I provided testimony in Case No. U-20165, the Company's Integrated Resource Plan case, and in Case No. U-18250, the Company's most recent securitization case before the Commission. In addition, I have also provided support for both Venkat D. Rao and Srikanth Maddipati who have served as the Company witnesses covering capital structure and cost of capital in each of the electric and gas rate cases before the Commission since joining the Company, including Case No. U-20650, the Company's current gas rate case, and Case No. U-20134, the Company's most recent electric rate case.

PURPOSE

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present my recommendation regarding the Return on Equity ("ROE") which should be used in computing the overall rate of return for Consumers Energy's electric business, as well as provide clarification regarding the financial incentives in the Company's Employee Incentive Compensation Plan ("EICP") Program.

Q. How is the remainder of your direct testimony organized?

A. My direct testimony is organized as follows:

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-14 (TAW-1)	Schedule D-5	Cost of Common Shareholders' Equity;

Exhibit A-114 (TAW-2)	Goldman Sachs Economics Research Report – September 18, 2019;
Exhibit A-115 (TAW-3)	ROE and Equity Relationship;
Exhibit A-116 (TAW-4)	John D. Quackenbush Testimony before FERC;
Exhibit A-117 (TAW-5)	PPUC Decision;
Exhibit A-118 (TAW-6)	S&P Global RRA Regulatory Focus Report – October 17, 2019;
Exhibit A-119 (TAW-7)	UBS Regulatory Report;
Exhibit A-120 (TAW-8)	Fama and French: *"The Cross-Section of Expected Stock Returns"*;
Exhibit A-121 (TAW-9)	Fama and French: *"The CAPM is Wanted, Dead or Alive"*;
Exhibit A-122 (TAW-10)	Financial Times: *"The time has come for the CAPM to RIP"*;
Exhibit A-123 (TAW-11)	Chartoff, Mayo, and Smith: "*The Case Against the Use of the Capital Asset Pricing Model in Public Utility Ratemaking"*;
Exhibit A-124 (TAW-12)	Chretien and Coggins: "*Cost of Equity for Energy Utilities: Beyond the CAPM"*;
Exhibit A-125 (TAW-13)	FERC Opinion No. 531-B;
Exhibit A-126 (TAW-14)	Federal Reserve: "*The Equity Risk Premium: A Review of Models"*;
Exhibit A-127 (TAW-15)	Brattle Group: "*Estimating the Cost of Equity for Regulated Companies*";
Exhibit A-128 (TAW-16)	Mississippi Public Service Commission Rate Schedule (Mississippi Power);
Exhibit A-129 (TAW-17)	Alberta Utility Commission, Decision 20622-D01-2016 (Extract);
Exhibit A-130 (TAW-18)	Value Line: "*Using Beta*";

Exhibit A-131 (TAW-19)	Gordon and Shapiro: "*Capital Equipment Analysis*"; and
Exhibit A-132 (TAW-20)	Additional Cost of Common Shareholders' Equity Analyses.

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

A. Exhibits A-14 (TAW-1), Schedule D-5; A-115 (TAW-3); and A-132 (TAW-20) were prepared under my direction and supervision. My remaining exhibits were gathered from numerous sources commonly relied upon by finance professionals in the course of their work.

I. SUMMARY OF ROE RECOMMENDATIONS

Q. What ROE is the Company recommending for Consumers Energy's electric business?

A. Based on the qualitative and quantitative analyses, a reasonable ROE range for Consumers Energy's electric business is 10.0% to 11.0%. While the analyses support a higher recommendation, because the Commission has a preference for adjustments to be limited to reasonable movements, and given the recommended equity ratio of 52.5% provided by Company witness Marc R. Bleckman, the Commission should approve an ROE at 10.5% at this time, which is the middle of the recommended range. This recommendation arises out of the consideration of numerous factors including: (i) the current state of the economy and capital markets; (ii) the need to continue to attract capital and maintain financial strength as the Company undertakes a large capital expenditure program designed to improve safety, reliability, and customer value; (iii) the risk profile of Consumers Energy's electric business compared to the proxy group; (iv) established principles for setting a fair ROE including ensuring the financial soundness and credit of the utility; and (v) results of various economic models used to calculate the cost of equity, all of which are described in detail in Section II.

Q. How does the Company's recommended ROE compare to your current authorized ROE?

A. The current ROE authorized by the Commission for Consumers Energy's electric business is 10.0%, which was established in the Commission's Settlement Order in Case No. U-20134, and is at the bottom of the recommended reasonable range. Given the capital structure recommended by Company witness Bleckman, an ROE of at least 10.5% is recommended, which is 50 basis points higher than the current authorized 10.0% ROE.

Q. Discuss why the Commission should increase the ROE?

A. While national ROEs may have trended downward in the years leading up to the Tax Cuts and Jobs Act ("TCJA" or "Tax Reform"), the Commission should note that national equity ratios have trended upward over the same period. As will be outlined in this testimony, ROEs and equity ratios are linked and must be viewed together to balance credit supportive financial metrics. As discussed by Mr. Bleckman in his direct testimony, the average equity ratio for the Company's peer group is 53.2% (see Exhibit A-26 (MRB-10)), which is meaningfully higher than the 52.5% being recommended by the Company in this case. If the Commission does not desire to raise the ROE to 10.5% given its preference for gradualism, the Commission could alternatively maintain an ROE of 10.0%. In that case, the Company would propose an equity ratio higher than the 52.5% recommended by Company witness Bleckman and would request approval of an equity ratio of 53.7%. This demonstrates that the level of an approved ROE requires a corresponding equity ratio that maintains credit supportive financial metrics.

This direct testimony and supporting analysis, along with that of Company witness Bleckman, provide justification for the 10.5% or higher ROE recommendation; however, in the event the Commission believes that a more modest increase in ROE is reasonable, such an outcome could be partially mitigated with a corresponding increase in the authorized equity ratio.

II. DEVELOPMENT OF ROE RECOMMENDATION

A. Importance of ROE and Financial Strength

Q. Discuss the importance of financial strength for a utility, including Consumers Energy.

A. The Company's nearly 1.8 million electric customers count on reliable electricity to power their homes, businesses, schools, and communities. Additionally, Consumers Energy's services play a key role in the economic development of Michigan by attracting industries that create jobs and invigorate communities. A strong, financially healthy utility is critical for providing this essential service.

As a regulated electric utility, Consumers Energy is obligated to serve all customers in its service territory. Doing so requires significant capital for both planned and unplanned investments in property, plant, and equipment. Customers and the state of Michigan are not well served if the Company's ability to meet these obligations is either subject to uncertainty or contingent on the instant state of the capital markets.

Q. Why is reliance on temporary markets a concern when evaluating the financial strength of a utility such as Consumers Energy?

A. Temporary market conditions can be disjointed from long-term patterns and, as such, it would not be in the best interest of customers to be completely reliant upon them. While, it is tempting to assume that markets will remain robust and capital will always be accessible, markets can deteriorate and have rapidly deteriorated in the past as evidenced during the Great Recession. When these markets deteriorate, there can be an upward surge in interest rates and, therefore, the cost of borrowing. Higher costs of borrowing for a utility means higher costs for making capital investments in property, plant, and equipment, fewer funds available for necessary projects, or both. A more recent example occurred in mid-September of 2019 when short-term interest rates spiked into the 10% area, requiring the Federal Reserve to inject significant liquidity into the markets in order to help return interest rate levels back to moderate ranges. This interest rate spike resulted from some idiosyncratic factors in the market, was a surprise to the investment community, and the effect is captured in the Goldman Sachs Economics Research Report from September 18, 2019, Exhibit A-114 (TAW-2).

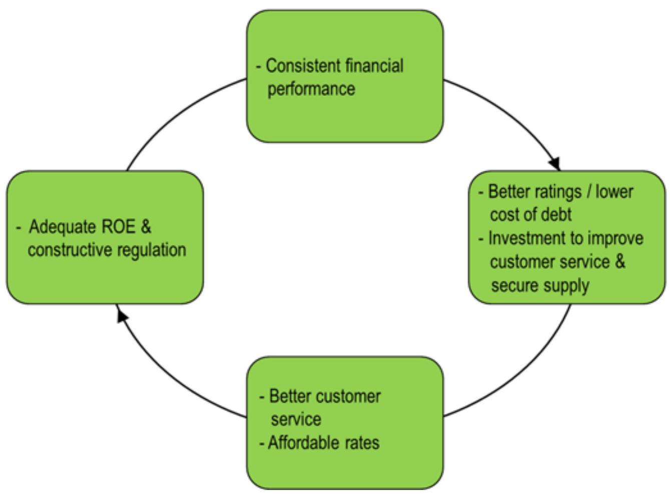
The capital markets have seen similar volatility and dislocations driven by health epidemics and social media messages surrounding potential military action and trade negotiations with a number of different Unites States trade partners.

Q. What is the practical effect of avoiding this type of volatility in the temporary market?

A. A financially strong utility that is not reliant upon temporary market conditions has a higher likelihood of maintaining access to capital at reasonable terms throughout the spectrum of possible capital market conditions, from robust to more capital constrained conditions as well. For businesses faced with financing and investing decisions that are not regulated and lack an obligation to serve, it is not uncommon for major investments to be deferred or canceled in response to tightening market conditions or shifts in economic cycles. Consumers Energy's customers, however, would not be well served by such a strategy, particularly market conditions resulting in the need to adjust work on major infrastructure projects that are geared toward maintaining or improving customer service and secure and reliable energy supply at affordable rates.

Q. Describe how utility regulation and ROE impact the financial strength of the utility.

A. The consistency, predictability, and promptness of regulatory outcomes, coupled with a constructive and supportive authorized ROE, are important parameters to enable a financially healthy utility. The following model demonstrates the benefits enabled by an attractive ROE and constructive regulation.



This "virtuous cycle," which is enabled by constructive and supportive regulation and attractive ROEs, is important for the Company to continue investing in its electric infrastructure. As the chart demonstrates, attractive ROEs are important and, in part, contribute to delivering consistent financial performance. Consistent financial performance contributes to better credit ratings and increased investment interest, thereby lower borrowing costs. The investment provided by utility shareowners, and the return allowed on that equity, provide the financial resources and capital to: (i) support the debt financing raised by the utility; (ii) procure contracts with suppliers; and (iii) fund unplanned or unexpected expenses.

Q. Do more attractive ROEs have other benefits?

A. Yes. The virtuous cycle starting with attractive ROEs continues with lowered costs of borrowing and enables affordable customer rates. Higher ROEs are also associated with higher customer satisfaction. Utilities with customer satisfaction in the top quartile have ROEs that are 50 basis points higher than those in the bottom quartile,[1] demonstrating that a reasonable ROE is not only important for investors, but reciprocally delivers value to customers as well. Thus, as demonstrated above, this reinforces the positive feedback of the "virtuous cycle," where a cycle of good regulation, together with a supportive ROE, enables a utility to attract capital and make investments that drive better service and maintain affordable rates.

Q. Discuss the role ROE has in capital allocation.

A. Capital is finite. As such, not all projects or investments can be funded, and a utility management team must decide which investments are most beneficial to customers and investors and should, therefore, be funded. While an attractive ROE enables the utility to maintain access to capital at a reasonable cost, access to capital is not the sole criteria used by a company to make an investment decision. Instead, both external and internal considerations must be weighed. Externally, private capital investment in the utility needs to be weighed against all other potential investments competing for capital. Internally, the management team, as fiduciaries, must weigh whether the Company's investment in the

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[1] J.D. Power's report, *How Customer Satisfaction Drives Return on Equity for Regulated Electric Utilities*, https://www.jdpower.com/sites/default/files/How%20Customer%20Satisfaction%20Drives%20Return%20On%20Equity%20for%20Regulated%20Electric%20Utilities%20White%20Paper.pdf

utility provides sufficient risk-adjusted returns relative to other options including electric utility investments, investments in other jurisdictions, non-regulated investments, or simply returning capital to shareowners in the form of dividends and/or share repurchases. While the investment community generally views the regulatory environment in Michigan as constructive and supportive, concerns over declining ROEs, or regulatory outcomes becoming less predictable, may cause a reassessment and deterioration of that view.

Q. Does the Company's ROE recommendation place an undue burden on ratepayers?

A. No. ROE is not the primary driver of customer bills and represents only approximately 20% of total costs. The recommended ROE would have a gross impact on the average residential customer bill increasing it by $0.48 per month. Impact on a "gross" basis is emphasized because this ROE impact may be partially offset by lower debt costs and improved access to capital markets given the aforementioned benefits of the "virtuous cycle."

Q. How does the Company view the needs of the customers versus the needs of the investors?

A. The Company recognizes and agrees with the need to balance customer and investor interests. Given the significant importance ROE plays in attracting cost-efficient capital and maintaining the financial health of the utility, however, an ROE and equity ratio consistent with the recommendation set forth herein ensures the continuation of the "virtuous cycle" and, as discussed above, is in the best interest of the customers we serve.

B. General Principles

Q. What are the general principles in setting a fair rate of return and return on common equity?

A. For regulated companies, the landmark *Hope* and *Bluefield* Supreme Court decisions have established the framework upon which a company's fair rate of return may be determined. In *Bluefield Water Works and Improvement Company v Public Service Commission of West Virginia*, 262 US 679 (1923), the United States Supreme Court stated that equity investors are entitled to a return commensurate with investments of comparable risk, that earnings must be sufficient to assure confidence in the financial soundness of the utility, and that a utility must be able to earn a return sufficient to support its credit and raise required capital. In *Federal Power Commission v Hope Natural Gas Company*, 320 US 591 (1944), the Court again stated that the return for common equity investors should be set at a level that is commensurate with returns on investments having corresponding risks. The Court also reiterated that the return should be sufficient to assure confidence in the financial integrity of the utility such that it is able to attract capital and maintain its credit. These principles are reflected in the ROE analyses provided and discussed in this direct testimony.

Q. How are ROE and rate of return related?

A. ROE is a measure of how much return a company is able to generate with each dollar of shareholder equity (investment) it receives. As discussed above, comparing the ROE of similar companies can help investors decide which constitute the most attractive investment choices. ROE is a significant part of a company's overall rate of return, which is the amount of return a utility earns, over and above its expenses.

Q. To support the principles reflected in *Hope* and *Bluefield,* what methodology was employed for setting a fair ROE?

A. Several analyses were performed to determine a reasonable ROE. Additionally, an analysis of the ROE and equity ratio that would support the Company's long-term Funds from Operation ("FFO")-to-Debt and credit was also performed. Finally, several quantitative models were employed to determine an appropriate return for investments having commensurate risk.

Q. Why were multiple methodologies and analyses employed to determine the requested ROE for this case?

A. As discussed above, an ROE and corresponding equity ratio may support the Company's credit but may not be commensurate with investments of similar risk and vice versa; therefore, the analyses performed looks at both the impact of the proposed ROE on the Company's credit as well as a comparison to similar investments.

Q. Is the determination of an appropriate ROE a precise calculation?

A. No. While the determination of ROE should be set at a level that is commensurate with returns on investments having corresponding risks, this calculation is not an exact science, and any methodology utilized is based on assumptions and inputs that may be less than certain. As a result, multiple methodologies were utilized because: (i) each of these methods, individually, will often produce a range of values, as illustrated by Exhibit A-14 (TAW-1), Schedule D-5, page 12; and (ii) the results of these quantitative models often make assumptions that do not necessarily fully reflect the returns that investors require, given current economic and financial conditions. As such, the application of multiple methods, in combination with an overall qualitative assessment of the marketplace, provides a more comprehensive evaluation of cost of capital and is most appropriate in evaluating the required cost rate for common equity capital.

Q. Please explain.

A. Each of the standard quantitative models assumes that economic conditions are relatively stable and that current market inputs are reflective of their long-term outlook. That assumption may not be true in current market conditions, mainly because of the unprecedented amount of central bank intervention and the impacts of the TCJA on the economy and credit quality of utilities observed during the last several years.

Q. What are the estimates produced by quantitative models representing?

A. Each of the quantitative models deployed produces an estimate of the required rate of return for an investor. If the expected return on investment is below the required rate of return, the management of a company will often cease making new investments and potentially seek to return capital unless returns are higher. If a company were to earn exactly the required rate of return, investors would be indifferent between new investment and the return of capital. In order to encourage investment, an ROE must be greater than the required rate of return. This point is best illustrated by considering the average earned return of the Standard and Poors ("S&P") 500 index.[2] In the last 12 months, the market earned an ROE that is 14% higher than that implied by standard model estimates.

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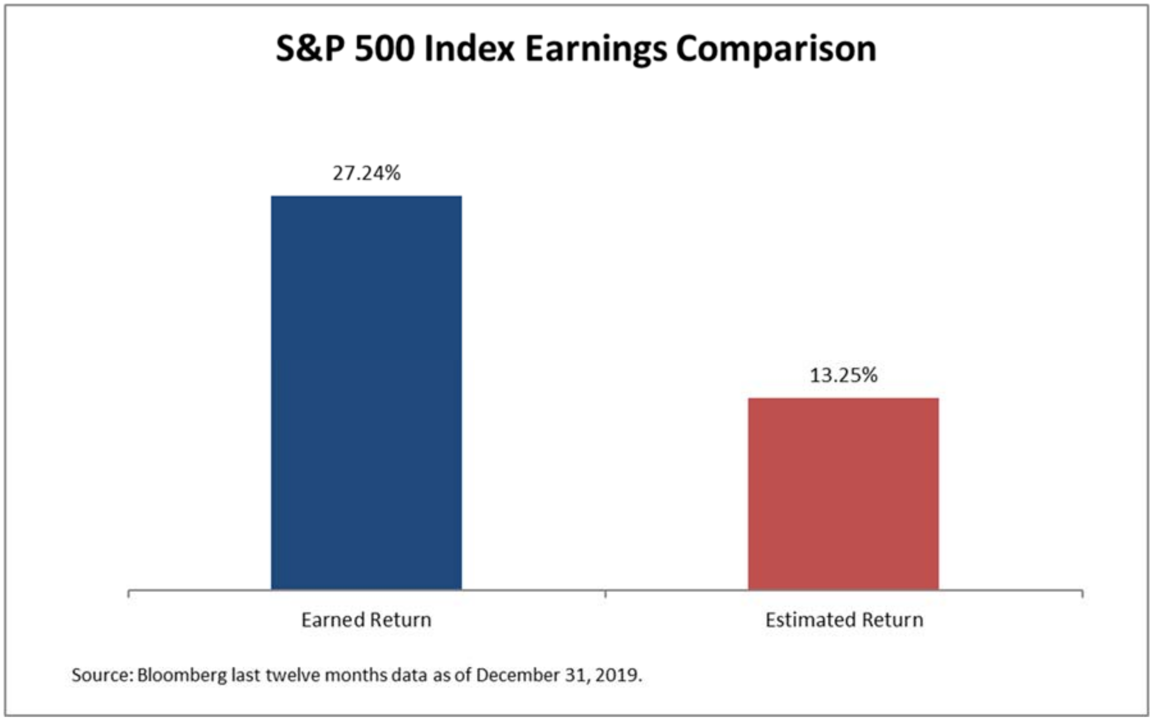
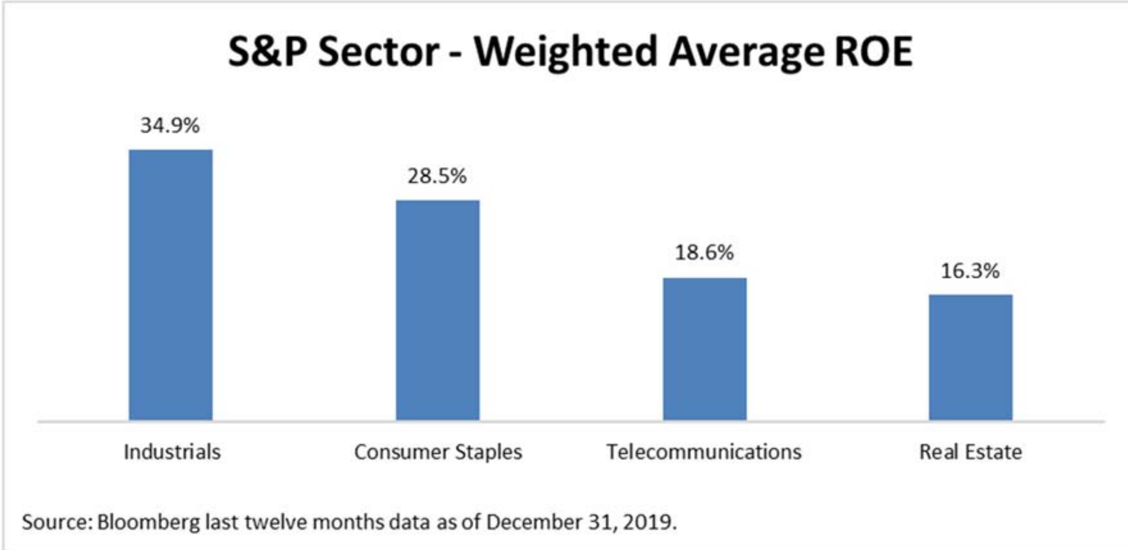
[2] Data provided by Bloomberg, as of December 31, 2019. See workpapers for support data and summary.



While the returns for the broader market are not necessarily the same risk as the utility sector, it is informative to look at other industries that are considered stable or lower risk. The chart below shows four S&P sectors and the earned return of each. It clearly demonstrates that investors may be able to realize competitive or superior returns from other investments with commensurate risk, and the utility sector is absolutely competing with each of them for investment dollars.



C. Summary of ROE Results

Q. Can you summarize the results of Consumers Energy's cost of common equity analyses?

A. The results of the analyses are displayed in Exhibit A-14 (TAW-1), Schedule D-5, page 12, and summarized in the chart below.

Summary of ROE Estimates

Projected Risk Premium ECAPM	8.75% - 11.04%
CAPM	14.3%
Projected Risk Premium	15.39% - 16.15%
Analyst Consensus DCF	7.15% - 11.84%
Comparable Earnings	8.43% - 12.58%
Recommended Range	**10.0% - 11.0%**

Based on analyses and consideration of the factors discussed below, an appropriate ROE range for Consumers Energy's electric business for the test year is 10.0% to 11.0%. The significant need to update the Company's and the state's energy infrastructure would suggest an ROE at the top end or even above the ranges shown in the analyses. The recommended ROE of 10.5%, however, is at the center of the reasonable ROE range.

Q. Is a 50 basis point increase in the proposed ROE appropriate?

A. Yes. While the Commission may view an increase of 50 basis points to be significant, in order to maintain the credit health of the Company as it pursues significant infrastructure and reliability improvements, this proposed ROE, in conjunction with the recommended equity ratio proposed by Mr. Bleckman, should be considered. If the Commission believes a 50 basis point ROE increase is too sizeable, then a higher-than-requested equity ratio would be a reasonable compromise, which is also discussed in the direct testimony of Company witness Bleckman.

D. <u>Qualitative Equity Cost Rate Considerations</u>

1. <u>Investor and Rating Agency Expectations and View of Regulatory Environment</u>

Q. How do investors view the current regulatory environment in Michigan?

A. Investors have generally viewed the regulatory environment in Michigan as supportive; however, this perspective can change since their interests and expectations are predicated on expected future outcomes. Utility investors continually weigh the relative risk of investing in a utility relative to other investments and, inherent in that decision, is an assessment of both the status and direction of the regulatory environment in which a utility operates. As fiduciaries, the management teams of utilities will also have a similar perspective, which dictates their capital allocation decisions on behalf of investors. As a result, if the investor view of the Michigan regulatory environment becomes less certain or less predictable, then they will be less inclined to invest further capital into Michigan utilities, which would lead to higher funding costs and would be detrimental to customers.

Q. Do investors and rating agencies make assumptions regarding the ROE for Consumers Energy?

A. Yes. The ROE authorized by the Commission and the ability of Consumers Energy to earn the authorized return are important factors considered by investors and rating agencies. In fact, a utility's authorized ROE and a consistent, constructive track record in this regard are key components in credit ratings assessments.

Q. Do you have examples of these assessments?

A. Yes. The June 23, 2017 *Regulated Electric and Gas Utilities Rating Methodology* for Moody's Investor Services ("Moody's"), for example, includes the following factors:

- Legislative & Judicial Underpinnings;
- Consistency & Predictability; and
- Sufficiency of Rates & Returns.

Similarly, S&P, in its *Key Credit Factors For The Regulated Utilities Industry,* reports the importance of earning a timely return:

> We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. S&P, November 19, 2013. (Emphasis added.)

In fact, S&P calls the ability to earn a timely return one of its "four pillars" in the "foundation of a utility's regulatory support."[3] These credit rating assessments provide confirmation that the authorized ROE and rates sufficient to earn the authorized ROE in this case are important signals that the Commission sends to the investment community.

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[3] S&P report, "Key Credit Factors For The Regulated Utilities Industry", November 19, 2013. See page 6.

Q. What has been your recent experience with investors and rating agencies as it relates to ROEs and risk?

A. As part of my role within the Company, I have had many conversations with investors and rating agencies, and though they recognize the general strength of Michigan's regulatory construct and legislative framework, several have expressed concerns regarding authorized ROEs and a resulting perceived deterioration in Michigan's regulatory environment. While one case or decision may not instantly shift investor views, a sequence of cases over time can create disappointment among investors. In fact, analysts noted the Commission's lower ROE in the Company's electric rate case (Case No. U-18322) as a concern, with one analyst highlighting "ROE creep" as an area of concern. ROE creep refers to progressively lower authorized ROEs in successive rate cases. This concern was realized by the Commission's September 26, 2019 Order in the Company's most recent gas rate case (Case No. U-20322). After the Commission's Order was issued in Case No. U-20322, Wolfe Research observed,

> The final order is a slight disappointment, as Michigan has finally fallen below the magic 10.0% allowed ROE threshold. [Wolfe Research, September 27, 2019.]

This comment is a direct reference to continued analyst concerns about ROE creep.

Q. How will investors view the Company's proposed ROE?

A. Investors are likely to consider an authorized ROE of 10.5% together with an equity ratio of 52.5%; the legislative impacts of 2008 Public Act ("PA") 286 ("PA 286"), 2016 PA 341 ("PA 341"), 2012 PA 342 ("PA 342"); and other regulatory adjustment mechanisms proposed by the Company, to be commensurate with the risks involved in investing in Consumers Energy.

Q. Has the Company considered the impacts of PA 286, PA 341, and PA 342 on investor risk perceptions?

A. Yes. Prior to PA 286, Michigan utilities faced long and uncertain processing times for rate cases compared to other states. By requiring a final rate order within 12 months of filing, PA 286 brought Michigan more in-line with other states. From an investor standpoint, while PA 286 reduced regulatory lag of case duration, it did not put Michigan in a more favorable competitive position than other states, as some other states require regulatory approval in less than 12 months. PA 341 reduced the overall time required for finalizing a rate case from 12 months to 10 months, but it did so while also eliminating the utilities' right to self-implement. Despite the shorter time period for receiving final rate relief, the Company will still only be allowed to request rate increases every 12 months. While the duration of the cases themselves will only be 10 months, the removal of the 180-day self-implementation included in the legislation introduced an additional source of regulatory lag. PA 341 actually <u>increases,</u> by four months, the time between filing a rate case and implementation of any rate increases. Overall, this aspect of the legislation does not reduce the risk faced by equity investors in the utility.

Q. Have rating agencies commented on the impact of Tax Reform?

A. Yes. Each of the agencies published reports on Tax Reform, and their respective titles highlighted the credit challenges faced by utilities considering Tax Reform:

> *U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound.* [S&P, January 24, 2018];

> *Tax Reform Creates Near-Term Credit Pressure for Regulated Utilities and Holding Companies.* [Fitch Ratings, Inc. ("Fitch"), January 24, 2018]; and

> *Tax reform is credit negative for sector, but impact varies by company*. [Moody's, January 24, 2018.]

Given the impact of Tax Reform, Moody's initially revised the outlook of 24 utilities to "negative" and continued in June 2018 by revising its outlook for the entire U.S. regulated electric and gas utility sector from "stable" to "negative." Moody's has downgraded the outlook and credit of numerous holding and utility companies, specifically citing Tax Reform's negative effect on company credit metrics as a main driver, if not the primary driver, for the ratings action. While Consumers Energy has not yet been put on negative watch, the inaction by ratings agencies has been predicated on the current constructive regulatory environment in Michigan, and the *expectation* that the Commission will consider the impacts of Tax Reform on credit.

Q. Have the rating agencies commented on any Michigan utilities?

A. Yes. As discussed in Mr. Bleckman's testimony and shown in Exhibit A-28 (MRB-12), on July 22, 2019 Moody's downgraded DTE Gas Company's long-term issuer credit rating from A2 to A3. The ratings rationale of the press release specifically cites TCJA impacts saying:

> [t]he robust investment program of DTE Gas, combined with the negative cash flow effect of federal tax reform, continue to put pressure on its financial metrics, weakening its overall credit profile… [Moody's, July 22, 2019.]

It is noteworthy that this action was taken *despite* recognition of a credit supportive regulatory environment and *despite* an authorized ROE of 10.0% and a 52% equity ratio.

Q. Are there ways to mitigate the credit risks imposed by TCJA?

A. Yes. In particular, the regulatory response will play a critical factor in mitigating these credit risks, and the credit rating agencies have specifically identified ROE and equity ratio as key tools for mitigating this impact as noted in the following excerpts from Moody's and Fitch:

> most utilities will attempt to manage the negative financial implications of tax reform through regulatory channels…They could propose to increase equity layer in rates or level of the authorized return on equity. In these cases, a cooperative regulatory relationship matters most for a given utility. [Moody's, January 24, 2018. (Emphasis added.)]
>
> Regulatory Support Key to Mitigating Downward Migration in Ratings…many tools could be employed, including increase in authorized equity ratio and/or return on equity. [Fitch, January 24, 2018. (Emphasis added.)]

As suggested by the credit rating agencies, public service commissions sending a clear message of support for increased ROEs and equity ratios will go far in signaling a cooperative regulatory environment and serve to solidify the Company's currently favorable credit.

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

A. A key metric that is used to identify the credit worthiness of a company, including Consumers Energy, is the ratio of FFO-to-Debt. As discussed in Company witness Bleckman's testimony at page 13, an FFO-to-Debt ratio is a financial metric that compares a company's cash flow from operating activities to a company's leverage, or debt outstanding. A higher FFO-to-Debt ratio, which reflects a cash flow from operating activities that is at a level viewed as favorable to offset or otherwise reduce the risk associated with the Company's ability to pay its debts, is indicative of a lower financial risk and a resulting higher credit rating. A higher credit rating, in turn, results in lower financing rates.

Two key factors that help determine this ratio are the Company's ROE and equity ratio. Exhibit A-115 (TAW-3) provides a mathematical development of how ROE and equity ratio determine a company's FFO-to-Debt ratio over the long term, assuming steady state conditions, and is in-line with Moody's ratings methodology. As Exhibit A-115 (TAW-3) also illustrates, reducing either ROE or equity ratio on a stand-alone basis results in a corresponding deterioration of the FFO-to-Debt ratio. Further, movement of the ROE and equity ratio pair from 10.5%/52.5% to the Company's 9.9%/52.05%, as determined in the September 26, 2019 Order in Case No. U-20322, would result in a further deterioration of 94 basis points in the resultant FFO-to-Debt ratio.

Q. Will an ROE/equity ratio pair of 10.50%/52.50% fully support the Company's current credit rating?

A. No. The methodology proposed by the Company most closely aligns with Moody's methodology and, as the Company has noted in prior cases, an FFO-to-Debt ratio of approximately 20% is the minimum level that would be supportive of the Company's current credit rating. Moody's noted in their most recent credit opinion that a factor that could lead to a downgrade is a "deterioration in financial metrics such as CFO pre-WC to debt falling below 20%"; therefore, an ROE or equity ratio higher than currently recommended by the Company would be justified. However, in recognition of the Commission's recent reduction in the ROE to 10%, and in further recognition that the Commission may be hesitant to reverse course and raise the ROE by 50 basis points in this instant case, if the Commission believes an ROE of 10.0% is more appropriate, then a higher equity ratio would be warranted.

Q. Please summarize the Company's conclusions regarding investor and credit rating agency expectations.

A. Based on interactions with investors and the rating agencies and their publications, it is clear that they view the authorized ROE as a critical metric which serves as the key barometer of the regulatory environment in Michigan. As such, a reduction to the authorized ROE will affect their perception of the credit quality of Consumers Energy and, thus, reduce their willingness to invest in Consumers Energy and, ultimately, in Michigan. While investors currently view Michigan's regulatory environment as fairly constructive, their assumptions are based on returned stability in regulatory outcomes. If investors and the credit rating agencies were to perceive the regulatory environment as further deteriorating, this would quickly undercut the view that they currently hold.

2. <u>Interest Rates</u>

Q. What role do interest rates play in cost of capital determinations?

A. Interest rates clearly play an integral role in cost of debt determinations and, because debt comprises a large portion of a utility's capital structure, interest rates also play a large role in determining a utility's overall cost of capital. Both short-term and long-term interest rates influence cost of capital, but the impact can vary depending on a company's capital structure. This is most clearly evidenced by Mr. Bleckman's Exhibit A-14 (MRB-1), Schedule D-1, which outlines the Company's overall rate of return and highlights the Company's capital structure both on a permanent capital and total capital basis. As seen in the exhibit, long-term interest rates are considered in the permanent capital structure as the cost rate of the long-term debt of the Company. Because most of the Company's outstanding long-term debt is of a fixed interest rate structure, long-term interest rates affect the planned financings of the Company. Short-term interest rates also affect a company's expenses, but it does not get considered in the permanent capital structure of the Company. The effects of long-term and short-term interest rates are differentiated, but both impact the Company's cost of equity analysis as will be discussed below.

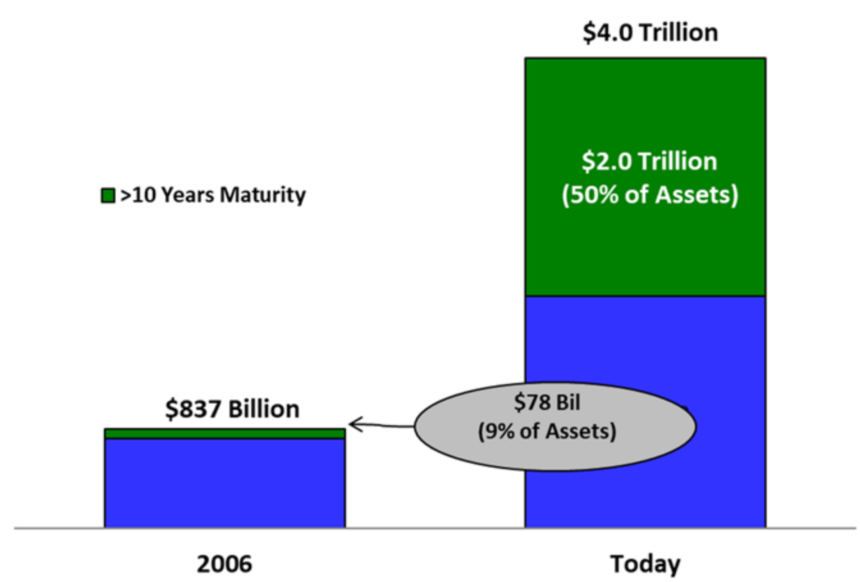
a. Long-Term Interest Rates

Q. What is the Company's assessment of current long-term interest rates?

A. Long-term interest rates have been, and continue to be, held low by the Federal Reserve as a response to anemic domestic and global economic growth. This policy of maintaining low long-term interest rates has been replicated by central banks around the world and is perhaps one of the single largest considerations influencing cost of capital for interest sensitive assets and, in particular, utilities.

Q. Is there evidence the Federal Reserve is actually carrying out this policy?

A. Yes. The Federal Reserve has kept long-term interest rates low through the unprecedented growth in their balance sheet and similar growth in the monetary supply in the country. The size of the assets owned by the Federal Reserve has grown and the size of the Federal Reserve's balance sheet increasing, the duration of the assets being held have grown dramatically. This combination of increasing balance sheet and purchasing longer-dated securities has had the effect of decreasing the supply of long-dated bonds and, therefore, lowering long-term interest rates per the Federal Reserve's policy.



Source: Federal Reserve, Schedule H.4.1 as of September 25, 2019.

Q. How have the actions of central banks outside of the United States impacted long-term Treasury rates?

A. Central banks outside of the United States have largely kept interest rates artificially low as developed countries continue to experience tepid growth. This has resulted in 37% of all developed country sovereign debt, over $15 trillion, having negative yields.[4] Furthermore, 96% of debt for developed sovereign bonds has a yield below that of the 30-year United States Treasury. These historic actions by central banks have made the rates offered by long-term United States Treasuries appear attractive on a relative basis, which has increased demand. However, as mentioned earlier, the supply of long-term treasuries has been drastically reduced by the Federal Reserve, which has increased the size of its balance sheet through purchases of long-dated securities. This combination of

[4] Data provided by Bloomberg, as of September 30, 2019. See workpapers for support data and summary.

low global yield and Federal Reserve intervention has affected both sides of the supply/demand relationship in favor of lower rates, and these market dynamics have resulted in long-term rates being artificially suppressed.

Q. How do the actions by the Federal Reserve and other central banks to keep long-term rates low influence the cost of capital analysis for utilities?

A. One of the key components in many of the quantitative models is the interest rate on long-term government bonds as a benchmark; however, in an environment where the Federal Reserve is purposefully keeping long-term interest rates artificially low, these unadjusted models become less reliable, which is well documented not only by the Federal Reserve but also academics and market practitioners alike. While unadjusted models would indicate diminished expected investor returns as a result of suppressed long-term government bonds, such a conclusion is erroneous. In fact, investors' expectations for investment returns do not simply decrease because of extraordinary intervention by central banks to lower rates.

Q. Has the MPSC Staff ("Staff") commented on the assertion that the Federal Reserve actions have artificially suppressed interest rates?

A. Yes. Staff has been critical of this assertion in the past, calling it stale and incorrect. The criticism, however, has focused on short-term interest rate hikes that have been imposed and ignored the continued state of long-term interest rates. However, a belief that multiple years of significant Federal Reserve intervention in the market should suddenly be considered normal compared to generations in which current market forces have been absent is simply not a reasonable one. Even if these conditions are now the "new normal," Staff should agree that the new normal years certainly cannot be reasonably compared directly to the previous generations of data for which there were no such accommodative policies altering market forces. The Company has taken this into account in the analyses.

Q. Does the current interest rate environment result in customer savings?

A. Yes, lower long-term interest rates lead to a lower cost of debt which decreases the overall cost of capital, and this benefit is passed on to customers.

Q. What has been the cost of debt for the Company in recent years?

A. Refer to Company witness Bleckman's Exhibit A-14 (MRB-4), Schedule D-2, which reflects the Company's debt issuances used to develop the annual cost for long-term debt. It is evident from this exhibit that the rates on the Company's long-term debt issuances have decreased substantially starting in late 2010. The Company's cost of long-term debt, as reflected in its August 2010 gas rate case filing (Case No. U-16418), was 5.95%, 200 basis points higher than the current case annual cost of 3.95%.

Q. Does the Company's lower cost of long-term debt equate to lower cost of equity?

A. No. The Company's lower cost of long-term debt should not be confused with a lower cost of equity. Cost of equity is impacted by several other factors, such as current economic uncertainty, market uncertainty and potential dislocation, higher equity risk premiums in low interest rate environments, and the sensitivity of utilities to movements in interest rates.

Q. How are the Company's credit ratings, long-term debt rates, and ROE connected?

A. The Company's favorable credit ratings over the past several years has resulted in lower long-term debt rates. The favorable credit ratings are due, at least in part, to the historically supportive regulatory environment and a reasonable authorized ROE.

Q. Is it a fair conclusion to believe a low interest rate environment, paired with the Company's improved credit ratings and financial stability, could justify a lower ROE?

A. No. This conclusion is erroneous and confuses the risk faced by bond investors with the risk faced by equity investors, which are important to differentiate.

Q. Please explain the difference between a bond investor and an equity investor and their relative investment risk.

A. Bond investors are simply lending their money to the company they invest in. The bonds receive interest payments over the life of the bond and the bonds deliver more consistent returns. In the event of corporate liquidity issue, bond holders are always paid first. On the other hand, equity investors are not just lending their money, they invest in the Company in exchange for part ownership. As such, their returns are not based on a stated rate of return and are much less consistent. In the event of a corporate liquidity issue, equity holders only have rights to what is left *after* the bondholders are paid.

Q. How does lower cost of debt function differently than lower cost of equity?

A. As stated above, the Company's improved credit ratings and lower interest rates lead to a lower cost of debt. Having a lower cost of debt decreases the overall cost of capital, and this benefit is passed on to customers. Exhibit A-14 (TAW-1), Schedule D-5, page 7, demonstrates how increased credit ratings save customers $88 million annually in interest savings. However, once again, a lower cost of debt should not be confused with a lower cost of equity. A downward movement in interest rates would not necessarily equate to a lower ROE for several reasons, including:

- Lower interest rates as a result of economic uncertainty and volatility can lead to lower Treasury Rates since they provide investors low risk safe havens for their investments; however, a higher ROE is necessary for investors willing to invest in higher risk stock to compensate for the additional risk;

- Equity risk premiums (the excess return that investing in higher risk stock provides over a risk-free rate (i.e. bond rate)) are higher when interest rates are lower which would lead to higher required ROE; and
- Utility stocks are particularly sensitive to interest rates and face increased risk, given that long-term interest rates have been and continue to remain artificially low due to monetary actions taken by the Federal Reserve.

Q. Has the Commission commented on the current low rate environment and its impact on ROE?

A. No. The Commission has not specifically commented on the impact that unprecedented monetary policy has had on ROE. However, in the development of appropriate ROEs, there has been federal and state recognition of the anomalous market conditions that have existed for more than a decade and should be, similarly, recognized by the Commission in this case. For example, in direct testimony before the Federal Energy Regulatory Commission ("FERC"), the former chairman of the MPSC, John D. Quackenbush, cited anomalous market conditions, and cited to the recognition by FERC of these anomalous market conditions in a number of FERC matters when testifying in support of ROEs in the high end of the zone of reasonableness in FERC Docket No. EL16-64-002. See Exhibit A-116 (TAW-4).

An additional example is found in a 2012 decision for PPL Electric Utilities, wherein the Pennsylvania Public Utility Commission ("PPUC") recognized that market conditions may have caused certain models to understate the cost of equity. See Exhibit A-117 (TAW-5), page 81. These recognitions highlight the fact that quantitative models provide output estimates that need to be considered in light of market conditions.

Q. How were limitations of mechanical application of quantitative models in the Company's ROE analysis?

A. The quantitative models typically utilized to determine required ROE rely on either static conditions or use of historical data as benchmarks that do not correctly reflect today's current market conditions or the market conditions in the future. The limitations of various models was addressed by employing multiple methodologies, using projections for market inputs (risk-free rates, dividends, and risk premiums), and using independent judgment based on conversations with and feedback from the investment community. Furthermore, the analysis includes a methodology for calculating the impact on credit metrics for both ROE and equity ratio.

b. <u>Short-Term Interest Rates</u>

Q. How are interest rates anticipated to move going forward?

A. The Federal Reserve has kept short-term rates near zero since late 2008 and, as a result, its purchase of longer duration assets has kept longer-term rates artificially low. Over time, the Federal Reserve will continue to look for ways to bring down the size of its balance sheet to more normal levels, which will put additional upward pressure on interest rates. This process began in December 2015 with the Federal Reserve's first rise in interest rates in nearly a decade and continued with nine total rate hikes before reversing course and, once again, lowering rates three times, starting in August of 2019. It is important to understand that these movements in short-term interest rates do not directly correspond with a move in long-term interest rates.

Q. Does the average of the interest rate expectations utilized in the analysis reflect the conditions in the test year?

A. No. Near-term expectations usually have some relative consensus; however, given the continued uncertainty regarding the economy, geopolitical actions, and actions from the Federal Reserve, near-term expectations have larger variation, and future periods demonstrate considerable variability as to expected yields. Given the sensitivity of utility stocks to interest rates, using simple averages would understate the risk given the elevated variability of expected outcomes. When interest rates rise, utility stocks are often the most impacted and, therefore, the cost of equity for utilities increases. This relationship has been apparent since late 2017 and continues today. With interest rates near historic lows, mean reversion suggests that interest rates will eventually rise, and this movement will increase utility cost of equity. It is, therefore, important to keep these circumstances in mind in setting the cost of equity for utilities. The quantitative analysis performed takes this critical factor into consideration.

3. ROE Trends

Q. Is there a source that serves as a complete provider of authorized ROEs around the country?

A. No. There is no accurate or complete source for the national ROE trends.

Q. Do you consider the *S&P Global Regulatory Research Associates* ("RRA") database a complete source for national ROE trends?

A. No. While the RRA database attempts to do so, it is incomplete.

Q. Please explain how it is incomplete.

A. The RRA database does not include: (i) alternative regulatory jurisdictions (i.e. Alabama, Georgia); (ii) ROEs set outside of general rate cases (i.e. California); (iii) cases where ROEs are settled/unstated; and (iv) jurisdictions that have separate riders (i.e. Wisconsin, Iowa, Virginia).

Q. Is this significant?

A. Yes. The data that is missing from the RRA database tends to support higher ROE values. As an example of just one type of exclusion, attractive authorized ROEs for generation assets in jurisdictions such as Iowa (11.0%) and Wisconsin (12.7%) do not get included in the headline average number reported by RRA as they are done so outside of a general rate case. RRA themselves point to this in their October 17, 2019 S&P Global Intelligence article on RRA regulatory rate case outcomes, presenting the following about jurisdictions with separate riders:

> Over the last several years, the annual average authorized ROEs in electric cases that involve limited-issue riders were typically meaningfully higher than those approved in general rate cases [See Exhibit A-118 (TAW-6), page 5.]

Q. How does this missing data affect an analysis of national ROE averages?

A. The missing data skews national ROE averages lower because numerous jurisdictions with strong regulatory frameworks that have constructive ROEs are not reflected in the RRA database. With jurisdictions increasingly approving ROEs outside of general rate cases, and with the majority of them receiving ROEs above the average number reported by RRA, it is no surprise that the average of remaining general rate cases has trended lower over time.

Q. Even though the RRA database is incomplete and should not be relied on, has that RRA data provided any helpful information regarding national ROE?

A. Yes. While the Commission should not rely on incomplete data, it is worth noting that the RRA Regulatory Focus from October 17, 2019, cites increases to both ROE and equity ratio through the first three quarters of 2019 compared to 2018. See Exhibit A-118 (TAW-6). Importantly, as it relates to equity ratios, that same report highlights a sustained increase in authorized equity ratios saying, "equity ratios have generally increased over the last 15 years." Thus, if the Commission continues to be persuaded by RRA data that tends to demonstrate lower ROEs, the Commission should also give equal consideration to RRA data that demonstrates equity ratios have, in fact, trended upward.

Q. What is the interplay between regulatory environments and ROEs?

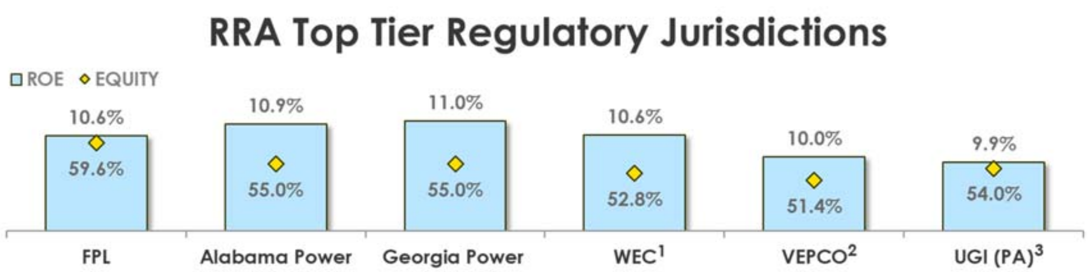
A. UBS produces an annual report that ranks individual states and Canadian provinces according to the quality of their regulatory environments. The 2018 UBS report shows that states with a regulatory environment in the top two quartiles earned ROEs, on average, of 11.5% and 10.0%, respectively, while states in the bottom two quartiles earned ROEs, on average, of 9.8% and 9.6%, respectively. The UBS report shown in Exhibit A-119 (TAW-7) demonstrates that there is a clear, positive relationship between the quality of the regulatory environment and ROE. Analysts, in turn, recognize this positive relationship and incorporate their expectations into their ROE estimates. This virtuous cycle of strong regulations coupled with an attractive ROE enables continued investment in necessary infrastructure., as discussed above.

Q. Are there examples of top tier regulatory jurisdictions and factors impacting their inclusion in that positive ranking?

A. Yes. RRA considers numerous factors in determining their regulatory jurisdiction rankings, including:

- ROE and equity ratio;
- Commissioner selection;
- Elected officials, legislation, and court actions; and
- Settlements, alternative regulation, adjustment clauses, rate structure, and rate case timing.

The chart below demonstrates examples of utilities operating in top tier regulatory jurisdictions, specifically the top two categories of RRA's ratings system.



1. Represents weighted average Wisconsin utilities.
2. Weighted average of all base rates and riders.
3. UGI is a gas utility company. Pennsylvania has only had one litigated case for any utility since 2012.

Top tier regulatory jurisdictions examine more than just one of the factors listed above, and jurisdictions with strong regulatory frameworks have higher customer satisfaction as well as higher ROEs. As an example, Florida authorized the Florida Power & Light ("FPL") ROE at 10.55% along with an equity ratio of 59.6%, and FPL was rated number two in customer satisfaction in the South Region in 2019. FPL trail only Georgia Power, another provider in a top tier regulatory jurisdiction.

4. Economic Outlook and Uncertainty

Q. Was the current state of the economy considered in performing the Company's ROE analysis?

A. Yes, national and global factors were considered. Several of the analysis inputs included market observations that are impacted by the current state of the United States economy. In addition, global economic factors play into investor considerations because of the ripple effects on the United States economy and the integrated nature of global financial markets.

Q. Why is it important to consider the economy in performing an ROE analysis?

A. The Company makes long-term investments in infrastructure to serve customers, but markets can and do face significant dislocations from time to time, which affects risk to investors. The most recent example of which is the Federal Reserve's injection of cash which was needed to stabilize volatility in the repurchase market mentioned earlier in this testimony. The competition for capital investment to fund projects has continued to increase, and all of these factors have increased uncertainty and utility investor risk in the market and, thus, impact an analysis of ROE.

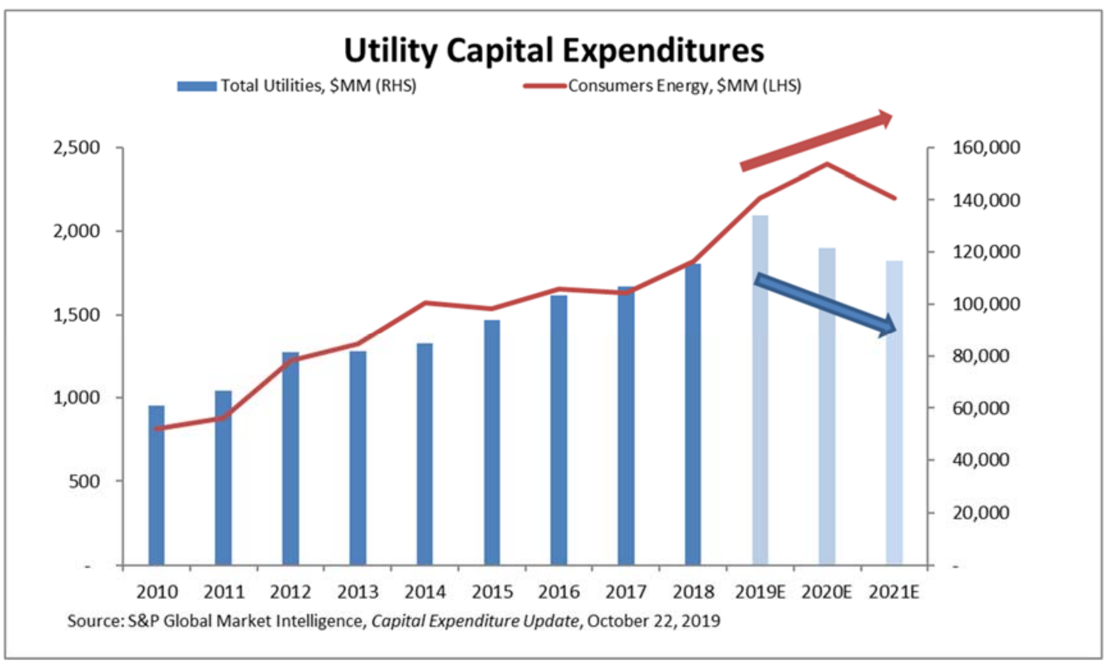
5. Capital Investment

Q. Does the Company's significant capital investment program impact the appropriate ROE determined in this case?

A. Yes. Consumers Energy plans to continue making significant needed capital investments in Michigan to provide safe and reliable service to customers, in compliance with federal and state requirements. Over the next five years, the Company plans to invest approximately \$11.8 billion on a total company basis, \$6.7 billion of which is earmarked for electric supply and electric distribution investment.[5] This significant level of capital investment increases the risk profile of the Company for investors and the rating agencies. Authorizing an ROE in this case at a level that investors view as adequate to compensate them for the risk is necessary to attract large amounts of cost-effective capital to Michigan and to keep Consumers Energy financially healthy to the benefit of customers. Authorizing an ROE that investors consider to be below expectations could lead to increases in cost of capital or hinder the Company's ability to access capital altogether, neither of which is in the best interest of customers.

Q. What is the trend in capital expenditures across the utility industry?

A. The following chart shows the historic and projected capital expenditures for the utility industry per *S&P Global* as well as historical and projected capital expenditures for Consumers Energy.



[5] See Consumers Energy 2019 Third Quarter 10-Q, page 19.

As the chart illustrates, while the industry is projected to have declining capital investment needs in the near term, Consumers Energy's investment has grown and the projected investment will remain elevated to make necessary upgrades to critical energy infrastructure. This heightened need for investment will require Consumers Energy to raise significant amounts of capital and a competitive ROE is critical to attract capital and enable investment.

Q. Please discuss the role of ROE in attracting capital.

A. One of the key principles in setting an ROE is to maintain the financial integrity of the utility so that it maintains its credit. Equally as important is setting an ROE that attracts capital. The State of Michigan has ambitious goals to improve the energy infrastructure which will require significant capital. While undertaking any major projects increases the risk profile of a company, public utilities are a primary vehicle to fund and execute these infrastructure investments. However, utility management teams cannot simply invest capital without evaluating its impact on investors, as they owe a fiduciary obligation to their shareowners and must be cautious when investing capital in a business where the ROE, relative to other projects, is less attractive. Michigan must compete for investment dollars with all the state jurisdictions highlighted earlier which provide ROEs that are significantly more attractive than the Company's current 10.0%. Further, if investors and management teams perceive the risk that invested capital would be subject to further downward pressure (ROE creep) in the future, they will be increasingly cautious about current investments in order to avoid this risk.

Q. How have other jurisdictions responded to this regulatory risk and what is the Company's recommendation?

A. Given the existence of this regulatory risk, several jurisdictions have established ROE riders and alternative mechanisms to ensure that the ROEs will not be subject to reduction. Examples include the attractive authorized ROEs for generation assets in jurisdictions such as Iowa (11.0%) and Wisconsin (12.7%) that were mentioned earlier.

Q. What is the Company's requested ROE in this case?

A. An ROE of 10.50%, 50 basis points higher than is currently authorized is within the range of reasonable returns, as will be demonstrated through the discussions of the quantitative analysis below. This ROE would send an important signal to investors that management is not investing in a company or state that has a declining regulatory environment.

E. Quantitative Equity Cost Rate Analyses

1. Selection of Proxy Companies

Q. Why was a group of proxy companies selected to perform the quantitative analyses?

A. Since the common stock of Consumers Energy is not publicly traded, it is necessary to use indirect or proxy approaches to calculate an appropriately representative ROE.

Q. Please describe how a proxy group of companies was chosen.

A. The focus of this case is on Consumers Energy's electric operations and companies similar to the Company's electric operations. Thus, the primary focus was on publicly-traded companies, companies headquartered in and with operations in the United States, companies with a comparable amount designated generation capacity, and companies with a comparable amount of Property Plant and Equipment ("PP&E").

Q. Please explain.

A. Proxy companies were selected as follows:

(i) The initial selection criteria were selected to identify electric utility companies that are publicly traded and for which public data is available. The *S&P Global* published data set, formerly referred to as *SNL Financial*, was utilized as the primary data set to select the initial proxy group.

(ii) In order to be included in the proxy group, the company had to be headquartered in and have the vast majority of operations within the United States.

(iii) The companies were also required to have regulated generation capacity greater than 2,000 MW. This eliminates companies that do not have significant generation assets as part of their businesses. Generation assets carry greater risk, both operationally and financially and, therefore, companies without meaningful generation assets are not good comparisons to Consumers Energy's electric business.

(iv) The companies were required to have net PP&E between $5 billion and $60 billion. This filter excludes both the very small as well as the extremely large ends of the spectrum of utility companies, thereby focusing on comparably-sized companies in the relative range of Consumers Energy's electric business. Academic literature has shown a correlation between company size and ROE (Fama, French, K. R.

(1992) – *The Cross-Section of Expected Stock Returns*), making this an important criterion to include. See Exhibit A-120 (TAW-8).

(v) The companies were required to have a dividend payout ratio in the last 12 months greater than or equal to 55%; and

(vi) The company had to: (a) not be a recent merger target or be recently engaged in significant restructuring, as this type of activity can materially distort a company's data to the extent it should not be credibly included in a proxy group; and (b) have bonds rated at or above a minimum investment grade of Baa3 by Moody's and BBB- by S&P.

Q. Which companies were excluded due to merger or restructuring issues?

A. As in Case No. U-20134, Entergy Corporation was excluded because of the ongoing restructuring that the company is experiencing while it exits the nuclear business. FirstEnergy Corporation was also eliminated from the proxy group due to the company's 2018 Chapter 11 bankruptcy filings and subsequent restructuring efforts.

Q. Were there other companies that were eliminated from your proxy group?

A. Yes. AES Corporation ("AES") was eliminated because the company derives the vast majority of its revenues outside of North America and is predominantly involved in contract and competitive generation operations, rather than in electric utility operations.

Q. How does this proxy group differ from the most recent electric rate case?

A. Applying the above criteria and making the described eliminations resulted in a proxy group of 12 companies. The list of the proxy group companies, the selection criteria, and the data supporting inclusion is set forth on Exhibit A-14 (TAW-1), Schedule D-5, page 1. The resulting proxy group is the same as the Company's group in Case No. U-20134 along with the addition of Evergy, whose merger of Great Plains Energy and Westar Energy was closed in 2018.

Q. Why was the *S&P Global* data set utilized to filter your proxy group rather than additional sources that had been referenced by the Company in past years?

A. The Company had previously utilized additional sources to filter the proxy group, to include *AUS* monthly reports. The *AUS* monthly data set was previously used to determine the classification of the business, but unfortunately, the service was discontinued as of September 2016. When the *AUS* data became no longer available, the Company moved completely to the *S&P Global* data set for proxy selection.

2. <u>Empirical Capital Asset Pricing Model Analyses</u>

Q. Please describe the Empirical Capital Asset Pricing Model ("ECAPM") model.

A. The ECAPM is derived from the Capital Asset Pricing Model ("CAPM") model which describes the expected rate of return on any security or portfolio of securities. The CAPM was first developed in the 1960s by William F. Sharpe, John Lintner, and Jack Treynor and had been used to estimate the cost of equity.

Q. What is the theory behind CAPM and ECAPM?

A. The principal assumption of the CAPM and ECAPM is that the expected return on an asset is related to risk – that is, risk taking by investors is rewarded with appropriate returns. The CAPM and ECAPM state that an investor's expected rate of return on an investment is equal to a risk-free rate of return plus a risk premium as a form of additional compensation for investors additional risk tolerance. The size of the risk premium for an investment is dependent on the amount of unavoidable (or systematic) risk taken. An investment's systematic risk is obtained by the application of a beta, which is a measure of the risk arising from exposure to general market movement and is used as an indication of the risk of an investment relative to the risk of a market portfolio consisting of all types of risk-oriented assets.

Q. Please explain the application of beta to determine risk premium.

A. Under the theory of CAPM, beta is a measure of the systematic risk of a security as compared to the systematic risk of the market as a whole. Beta is a coefficient resulting from a regression of the return of a single stock to the return of the market. The beta for the market is always equal to 1.00. Companies whose securities have betas greater than 1.00, therefore, are generally considered riskier than the market as a whole, while companies with betas less than 1.00 are generally considered less risky than the market as a whole. CAPM is based on the concept that investors demand higher returns for assuming additional risk and, accordingly, higher risk securities are priced to yield higher returns than lower risk securities. Under CAPM theory, there is an incremental premium for bearing additional risk, as measured by beta, above the risk-free rate, which is traditionally seen as the income return available from investing in United States Government Treasury securities (bonds). The model assumes that prices for individual securities are determined in efficient markets where information is freely available and instantaneously reflected in security prices. The specific CAPM formula is expressed as:

Equation (1): $K_e = R_f + F + B \times (R_p)$

Where:

K_e = annual required cost of equity;
R_f = risk-free rate;
F = flotation cost adjustment;
β = beta; and
Rp = risk premium which reflects the market return less the risk-free rate.

Q. Do CAPM results capture all the risk faced by utility investors?

A. No. The CAPM has a number of shortcomings which are particularly relevant to public utilities and are well documented in academic literature:

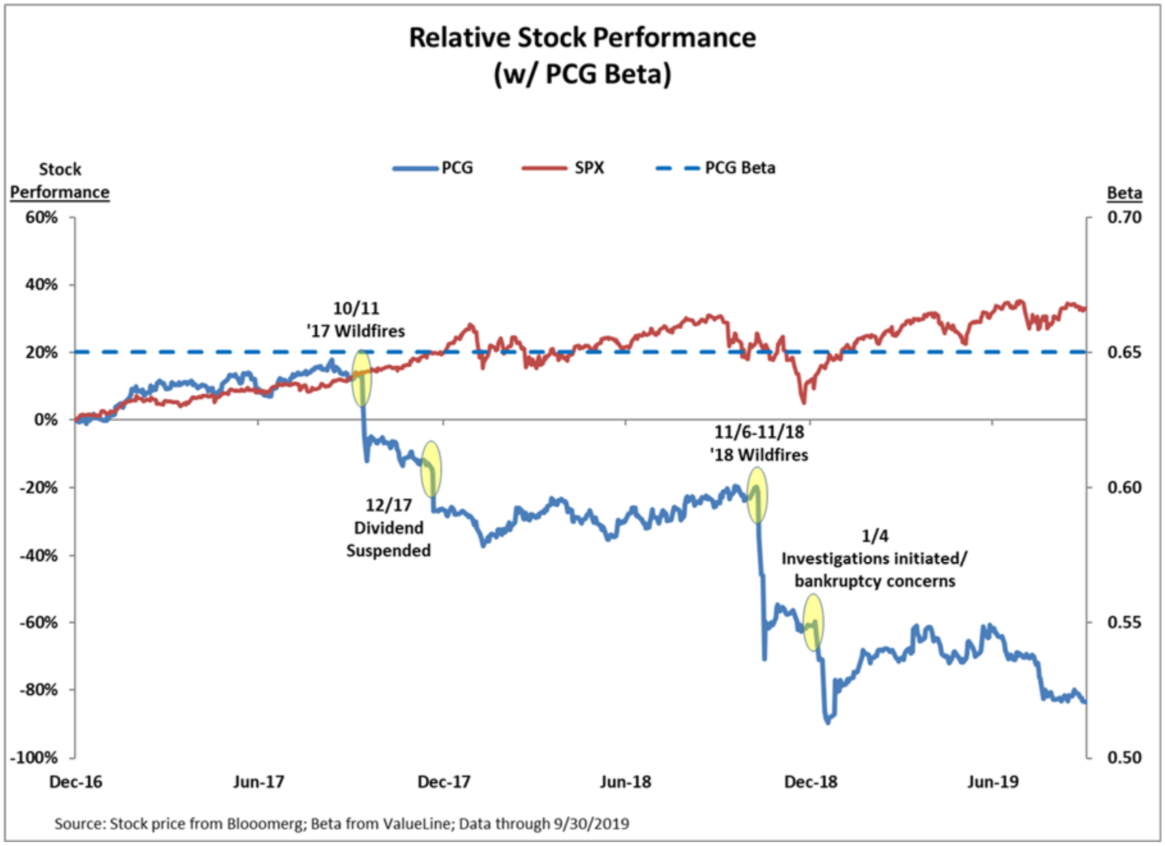
- Fama and French: "*The CAPM is Wanted, Dead or Alive,*" (Exhibit A-121 (TAW-9));
- Tony Tassell: *"The time has come for the CAPM to RIP," Financial Times,* (Exhibit A-122 (TAW-10));
- Chartoff, Mayo, and Smith: "*The Case Against the Use of the Capital Asset Pricing Model in Public Utility Ratemaking,"* (Exhibit A-123 (TAW-11));
- Chretien and Coggins: "*Cost of Equity for Energy Utilities: Beyond the CAPM,*" (Exhibit A-124 (TAW-12)); and
- Robert Morin: "*New Regulatory Finance."*

Q. Please summarize the shortcomings.

A. First, studies have shown that the CAPM tends to overstate the sensitivity of the cost of capital to beta. Low beta assets tend to have higher average returns than would be predicted, while high beta assets have lower returns. The beta of utilities, including the Company's proxy group, as shown on Exhibit A-14 (TAW-1), Schedule D-5, page 2, are typically less than 1.00 and would, therefore, tend to have higher average returns than predicted by the model. Second, CAPM relies on beta to capture all the systemic risk faced by a company and assumes that the only unavoidable (or systemic) risks are fluctuations in the market. Market beta calculates a low result for a company with a low correlation to the broad market when, in fact, the company could experience high stock volatility that is simply not correlated with the market. Utilities are interest rate sensitive and exposed to regulatory risk, neither of which market force is captured by the traditional CAPM analysis.

Q. Is there an example of how beta does not capture all the risk faced by a company?

A. Yes. As an example of how beta does not appropriately capture the risks associated with a stock, one can look at Pacific Gas and Electric Company ("PG&E"). The chart below shows PG&E's stock price over the course of the past two years as compared to the S&P 500 index. During this time PG&E was faced with increased risk of wildfire liabilities, along with ensuing dividend suspensions, investigations, and bankruptcy concerns. Clearly the stock has exemplified heightened risks over the period as the stock performance has underperformed both the UTY index as well as the S&P 500 index over the course of this time. The stock has also demonstrated a high correlation with wildfire risk rather than a correlation with the market performance as a whole. However, PG&E's Value Line Investment Survey ("Value Line") beta was 0.65 on January 27, 2017, as filed in the Company's 2017 electric rate case, Case No. U-18322, and remained at 0.65 in 2019. As discussed earlier, this is a low beta which would normally be indicative of low risk compared to the market. However, knowing PG&E's problems, this clearly demonstrates that traditional Value Line utility beta customarily applied to CAPM does not fully capture the entire risk faced by the underlying company, even when those risks threaten the viability of the company itself.



Q. Did the Company perform its customary CAPM methodology?

A. In previous cases before the Commission, the Company performed and relied upon a CAPM analysis but, given the voluminous evidence that the CAPM methodology understates the required rate of return for utilities, it was not relied upon in forming the recommended ROE range in this case. While a traditional CAPM analysis was performed for reference (Exhibit A-132 (TAW-20), page 1), reliance upon it is not appropriate.

Q. How did the Company address the customary CAPM model shortcomings referenced above?

A. In order to adjust for the shortcomings of the CAPM model, the Company performed the ECAPM analysis as well as CAPM analysis using total beta.

Q. Please describe the ECAPM approach.

A. The ECAPM begins with the same assumptions as the CAPM. To better predict the relationship between asset returns and risk, the ECAPM includes an "alpha" adjustment to the risk-return line. The specific formula of ECAPM is expressed as:

Equation (1a): $K_e = R_f + \alpha + F + B \times (R_p - \alpha)$

Where:

K_e	=	annual required cost of equity;
R_f	=	risk-free rate;
α	=	alpha;
F	=	flotation cost adjustment;
β	=	beta; and
Rp	=	risk premium which reflects the market return less the risk-free rate.

Q. What is alpha in this ECAPM approach?

A. The alpha adjustment in the ECAPM approach is simply an adjustment made to CAPM formula to more closely align the expected returns with market observed results.

Q. What values were assumed for the components of this analysis?

A. Except for alpha, which is not a component of the CAPM formula, the same values as the CAPM were used. For alpha, 1.5% was applied, which is the mid-point in the range of 1% to 2% described as reasonable by Dr. Morin in his book *New Regulatory Finance*.

Q. Does the application of long-term risk-free rates and adjusted betas fully address the concerns that ECAPM is meant to reconcile?

A. No. Application of a long-term risk-free rate and adjusted betas address some of the CAPM shortcomings, but it does not fully address the shortcomings of CAPM. Alpha adjustment is still necessary to address the key differences between CAPM and ECAPM. In fact, without the use of adjusted beta and long-term risk-free rates, the alpha adjustment would need to be higher than the proposed 1.5%.

Q. What are the results of applying the ECAPM on the group of proxy companies?

A. The ECAPM results are found on Exhibit A-14 (TAW-1), Schedule D-5, page 2. The Projected Risk Premium ECAPM ROEs are displayed in column (h) and show the average ROE for the proxy group is 9.38% and ranges from a minimum of 8.75% to a maximum of 11.04%.

Q. How was the market risk premium determined?

A. Since the equity risk premium may be fundamentally higher in different market conditions, the analysis must use market periods which mirror the conditions in the current environment in order to best approximate the current equity risk premium. As shown in Exhibit A-14 (TAW-1), Schedule D-5, page 11, a projected, or forward-looking, market risk premium was estimated based on the expected market return of the S&P 500 Index and subtracted the expected yield of the 30-year United States Treasuries during the projected test year. The expected market return was calculated as the summation of the dividend yield and the long-term Earnings Per Share ("EPS") growth estimates for the entire index. The estimated market capitalization weighted dividend yield of 1.86% and long-term EPS growth estimate of 11.39% resulted in a sum expected market return of

13.25% as of December 31, 2019. Subtracting the expected 30-year United States Treasury yield of 2.92% for the test period results in an estimated market risk premium of 10.33% for the test period.

Q. Is there support for a forward-looking market risk premium such as this?

A. Yes. Because the test year is in the future, it makes sense that the analyses supporting Company recommendations rely on projected market data to estimate returns for the forward-looking period; therefore, projected inputs and assumptions are appropriate to use where possible. In fact, in Opinion 531-B, FERC gave specific endorsement to a method that is similar to the method the Company has applied to calculate the forward-looking market risk premium, referencing both the S&P 500 Index as well as the 30-year United States Treasury bond yields. See Exhibit A-125 (TAW-13), at paragraphs 109-111.

Q. Did any other analyses support the Company's projected estimate?

A. Yes. Four additional equity risk premium estimates have been provided which are supportive of the resulting 10.33% value utilized in the analyses: (i) equity risk premium since quantitative easing began; (ii) equity risk premium during periods of Federal Reserve intervention in long-term interest rate markets; (iii) equity risk premiums from Federal Reserve research; and (iv) the Staff calculated estimate in Case No. U-20359 (Indiana Michigan Power Company's most recent electric rate case). The first two utilize Roger Ibbotson's *2018 Stocks, Bonds, Bills, and Inflation (SBBI) Yearbook.* Exhibit A-14 (TAW-1), Schedule D-5, page 8, lines 56 and 58, focus the calculations on the low interest rate periods of 2011 through 2018, and from the low interest rate periods of 1942 through 1951 and 2011 through 2018 on line 58. The Ibbotson data is often used in developing the market risk premium. These calculations take the average large company's total stock market return for the period and subtract the average income return of long-term government bonds for the period. The equity risk premium is not a known and static number, but it varies around a central average. Academic literature shows that, in low-interest rate environments, the average equity risk premium is higher. This is not to suggest that the realized equity risk premium will not vary in a low-interest rate environment but, instead, that the average is fundamentally higher. Taking the average of the available data during low-interest rate environments provides a more reasonable and accurate measure of the expected equity risk premium than applying one for all historical data available. The resulting market premiums for these periods are 9.02% and 12.73%, respectively.

The third estimate relies upon a recently published report by the Federal Reserve, *The Equity Risk Premium: A Review of Models*, Exhibit A-126 (TAW-14) which indicates that equity risk premiums in low interest rate environments are much higher – 12%. The fourth estimate is taken from the direct testimony of Staff witness Kirk D. Megginson in Case No. U-20359 on October 17, 2019[6]. Staff estimated the risk premium to be 12.10%, which is considerably higher than my estimate in this case. Each of these estimates is

[6] Direct testimony and exhibits of Kirk D. Megginson, MPSC Case No. U-20359 (October 17, 2019), page 16.

shown in the following table and each is supportive of the Company's projected estimate. The average is 177 basis points in excess of the 10.33% estimate applied in the analysis.

Equity Risk Premium	
Risk Premium During Most Recent Low Interest Rates (2011-2018)	9.02%
Risk Premium During Federal Reserve Action (1942-1951 and 2011-2018)	12.73%
Federal Reserve Research	12.00%
Staff Estimate in MPSC Case No. U-20359	12.10%
Average	**11.42%**

Q. Is it appropriate to use the average from 1926 to 2018 for the Ibbotson equity risk premiums with current risk-free rates?

A. No. The Ibbotson equity risk premium is an estimate based on historical data which is not appropriate to use with current interest rates, in particular during a period where the Federal Reserve is purposefully keeping long-term interest rates low. Utilizing current risk-free rates requires estimating a current equity risk premium as set forth in the Company's primary calculation.

Q. How were the projected risk-free rates calculated?

A. As in the past, the test year risk-free rate was calculated by utilizing an average of *Blue Chip* and *IHS Markit* 30-year United States Treasury Bond yield estimates. According to the December 2019 edition of *IHS Markit's* United States Economic Outlook, the average yield on 30-year United States Treasury Bonds for the test year is projected to be 3.04%. The estimate for 30-year United States Treasury Bonds from the December 1, 2019 *Blue Chip* Financial Forecast for the test year is 2.80%. The average of the two results in an estimate of 2.92%.

Q. Why were longer dated bonds chosen?

A. The time horizon of the chosen Treasury security should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the yield of a long-term Treasury bond is appropriate.

Q. What beta was used for purposes of the Company's ECAPM analysis?

A. The values of beta calculated by Value Line were used. Value Line computes historical betas using data over the last five years and adjusts this historical beta using the method prescribed by Marshall E. Blume to make it an expected beta. The exception is for the Evergy beta, which has not yet been published by Value Line and, therefore, Bloomberg was used to replicate the estimation which Value Line applies. The resulting betas are used in ECAPM analyses, and the values of beta for the Company's proxy group of companies are found on Exhibit A-14 (TAW-1), Schedule D-5, page 2. The average current beta for the Company's proxy group is 0.56.

Q. Does the ECAPM address all the shortcomings of CAPM?

A. No. ECAPM is focused on the understatement of ROE for low beta stocks and does not necessarily capture all the systematic risk associated with a stock.

Q. Is there third-party support for the use of ECAPM?

A. Yes. As discussed earlier in this direct testimony, the CAPM has several deficiencies which impact utilities in particular. There are numerous academic articles that have discussed the shortcomings of CAPM. The simple adjustments formulated by Dr. Morin to correct these deficiencies were used. Dr. Morin's detailed analysis of the ECAPM can be found in chapter 13, page 189, of his 1994 book, *Regulatory Finance*, and chapter 6 of his latest book, *The New Regulatory Finance*, both published by Public Utilities Report

Inc. In addition, findings from a February 2013 report from the Brattle Group entitled "*Estimating the Cost of Equity for Regulated Companies*" (Exhibit A-127 (TAW-15), pages 15-20) reinforce the many weaknesses in the CAPM model as well as the suitable application of the ECAPM to correct for these deficiencies.

Furthermore, an academic research paper focused specifically on utility companies in North America titled *"Cost of Equity for Energy Utilities: Beyond the CAPM"* (Exhibit A-124 (TAW-12) concluded the following:

> We find that the CAPM significantly underestimates the risk premium for energy utilities compared to its historical value by an annualized average of more than 4%.

The study looked at CAPM extensions to remove the underestimation error, one of which is an adjusted CAPM similar to the ECAPM in the Company's analysis. The research states that, unlike CAPM, the adjusted CAPM, "[p]rovide(s) econometric estimates of the risk premium that do not present a significant misevaluation." This is yet another clear example that the use of ECAPM in the Company's analysis is not only supported and logical, but necessary in setting a fair ROE.

Q. Beyond academic literature, are there examples of applications of the ECAPM analysis as used by the Company?

A. Yes. The ECAPM has been utilized in rate case proceedings and is included among the models relied upon by some regulatory witnesses and decision makers. For example:

(i) A 2013 study by Christensen Associates commissioned by the Mississippi Public Utilities Commission Staff called *Discussion of the Return on Equity and Performance Indicators of Entergy Mississippi Inc. and Mississippi Power Company*, explicitly acknowledges the Mississippi Power Company's use of Value Line betas in the applied CAPM (Empirical) calculations. The rate schedule from Mississippi Power showing the use of ECAPM with a Value Line adjusted beta has been included. Please refer to Exhibit A-128 (TAW-16), page 24;

(ii) The ECAPM approach has been relied on by the Staff of the Maryland Public Service Commission. For example, Staff witness Julie McKenna in Maryland PSC Case No. 9299 noted that "the ECAPM model adjusts for the tendency of the CAPM model to underestimate returns for low Beta stocks," and concluded that, "I believe under current economic conditions that the ECAPM gives a more realistic measure of the ROE than the CAPM model does";[7]

(iii) The Regulatory Commission of Alaska has also relied on the ECAPM approach, noting that:

> Tesoro averaged the results it obtained from CAPM and ECAPM while at the same time providing empirical testimony that the ECAPM results are more accurate then [sic] traditional CAPM results. The reasonable investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result;[8]

(iv) The Staff of the Colorado Public Utilities Commission has also recognized that, "[t]he ECAPM is an empirical method that attempts to enhance the CAPM analysis by flattening the risk-return relationship,"[9] and relied on the same standard ECAPM equation presented above;

(v) The Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, has also relied on this same ECAPM formula in estimating the cost of equity for a natural gas utility, as have representatives of the Office of Arkansas Attorney General and the Office of Oklahoma Attorney General;[10]

(vi) Additionally, Shannon Pratt and Roger Grabowski's book, *Cost of Capital in Regulated Utilities: Applications and Examples*, describes how the Surface Transportation Board significantly revised its approach to setting the cost of capital to include the ECAPM analysis as one of only two methods over eight years ago. The Minnesota Department of Revenue included ECAPM as one of the methodologies used in determining the value of property in their 2019 Assessment;[11]

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[7] Direct testimony and exhibits of Julie McKenna, Maryland PSC Case No. 9299 (October 12, 2012), page 9.
[8] Regulatory Commission of Alaska, Order No. P-97-004(151) (Nov. 27, 2002), page 145.
[9] Proceeding No. 13AL-0067G, answer testimony and exhibits of Scott England (July 31, 2013), page 47.
[10] Docket No. 30011-97-GR-17, pre-filed direct testimony of Anthony J. Ornelas (May 1, 2018), pages 52-53; Docket No. 17-071-U, direct testimony of Marlon F. Griffing, Ph.D. (May 29, 2018), page 47; and Cause No. PUD 201800140, responsive testimony of Marlon F. Griffing, Ph.D, (April 22, 2019), pages 41-43.
[11] https://www.revenue.state.mn.us/sites/default/files/2019-05/Caprate_Rate_Report.pdf

(vii) The New York State Public Service Commission has utilized what they refer to as the zero beta CAPM analysis dating back as early as the 1980s. Zero-beta CAPM is another name for ECAPM, as it references the traditional CAPM model's inability to capture necessary return for a zero-beta stock in excess of the riskless rate. The commission confirmed their reliance upon the zero-beta model as recently as April 20, 2017 in the final order in Case No. 16-G-0257, at page 53; and

(viii) Outside the United States, the Alberta Utility Commission's decision 20622-D01-2016 in October 2016 determined the ECAPM model could contribute to that commission's established fair allowed ROE. The commission in that jurisdiction noted in its findings, "[t]he use of ECAPM is an approach recognized in the academic literature and is used to address a perceived issue with the CAPM…." While this case did not have enough information to rely heavily on the ECAPM, they did recognize its relevance as well as academic support and stated that it could be used to determine an ROE. Please refer to Exhibit A-129 (TAW-17).

While not an exhaustive list of examples, the use of ECAPM in these regulatory proceedings demonstrates that it is neither new nor novel.

Q. Is the use of Value Line adjusted beta consistent with ECAPM?

A. Yes. Adjusted betas are used in the ECAPM analysis performed by regulatory witnesses referenced above in at least Alaska, Arkansas, Colorado, Maryland, New York, and Oklahoma, as well as the cost of capital proceedings in Mississippi. Furthermore, in Dr. Morin's book, *The New Regulatory Finance*, at page 191, he explicitly states the use of adjusted beta is necessary and that suggestions to the contrary are erroneous. He said:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. **This argument is erroneous**. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of

> adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated….**Both adjustments are necessary**. [Emphasis added.]

Further, Value Line clearly discloses in Exhibit A-130 (TAW-18) that the Value Line calculation for beta uses historical data, and the adjustment prescribed by Marshall Blume <u>does not incorporate the effects captured in ECAPM</u>. The use of Value Line adjusted betas is, therefore, very much consistent with the application of ECAPM.

Q. Has the MPSC commented on or otherwise rejected the use of the ECAPM?

A. No.

Q. Has Staff challenged the use of ECAPM in prior rate cases?

A. Yes. In Case No. U-20322 Staff cited Dr. Morin's book, *The New Regulatory Finance,* to assert that the application of Value Line beta and long-term treasury rates address the shortcomings of CAPM and make ECAPM unnecessary.

Q. Was Staff correct in its assertion regarding Dr. Morin's treatise?

A. No. First, other practitioners use ECAPM with both long-term Treasury Rates and Value Line beta. Further, in Dr. Morin's book, he notes that the empirical evidence on the appropriate range of the alpha factor is higher than the 1% to 2% alpha adjustment that the Company has proposed. Dr. Morin specifically states in *New Regulatory Finance,*

> An alpha adjustment of <u>**1%-2% is somewhat lower than that estimated empirically**</u>. The use of lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk free rate rather than a short-term risk free rate already incorporates <u>**some**</u> of the desired effect of using the ECAPM. [*New Regulatory Finance*, page 190. (Emphasis added.)]

Consistent with his book, Dr. Morin has testified in regulatory proceedings in other jurisdictions where he uses both Value Line beta and long-term interest rates with the ECAPM. Thus, Staff's argument has demonstrated a misunderstanding of the use of adjusted betas with ECAPM.

Finally, in the academic literature the "*Cost of Equity for Energy Utilities: Beyond the CAPM*" (Exhibit A-124 (TAW-12)) the authors explicitly note the use of adjusted betas with ECAPM and say:

> In summary, the two modifications incorporated in the Adjusted CAPM [ECAPM] involve first using the adjusted beta instead of the historical [raw] beta and second including the bias correction in the risk premium calculation. Considering the documented usefulness of the two adjustments, the Adjusted CAPM has the potential to estimate a reasonable risk premium for the energy utilities. [Exhibit A-124 (TAW-12), page 19].

Q. Please describe the CAPM approach using total beta

A As noted earlier, the CAPM approach relies on the use of market beta to capture the risk associated with a company but as highlighted with examples and academic literature, market beta simply fails to capture all the risks of an investment.

Furthermore, using a traditional CAPM to calculate Consumers Energy's ROE inherently makes several assumptions including that Consumers Energy is publicly traded, and faces no company-specific risks or can diversify those risks by making other investments. This is clearly not true – Consumers Energy is not publicly traded and, given its role as a Michigan-based public utility, cannot diversify away from Michigan.

To account for these shortcomings of a traditional CAPM, practitioners have used the CAPM model with total beta. Total beta is similar to market beta, but it accounts for the company-specific risks. Total beta is calculated simply as the standard deviation of a stock divided by the standard deviation of the market. As discussed above, market beta does not address all the risk of a market. The total beta is focused on volatility of returns and better identifies all associated risk – systematic risk *and* company specific or sector specific risk – which are not fully addressed by market beta for utility stocks. The simplicity of this approach allows for analysts to address the company-specific risk of a privately held company by comparing the volatility of a proxy group to that of the market.

Q. What are the results of applying CAPM using total beta on the group of proxy companies?

A. The CAPM with total beta results are found on Exhibit A-14 (TAW-1), Schedule D-5, page 3. The results are displayed in column (h) and shows an ROE estimate of 14.30%.

Q. Is this a new or novel approach to calculating CAPM?

A. No. The merits of total beta have been discussed and analyzed by experts for well over a decade. The total beta concept was further popularized by its inclusion in Peter Butler and Keith Pinkerton's Butler Pinkerton Model ("BPM")[12].

3. Projected Risk Premium Analysis

Q. Please describe the risk premium analysis that was performed.

A. Investors can choose to invest in either debt or equity in a company. Debt is subject to less risk as it receives a priority claim on assets in bankruptcy relative to equity. Further, interest payments, unlike dividends paid on equity, are mandatory and cannot be deferred. Investors in equity securities, therefore, demand a premium relative to the return paid on the debt. The risk premium analysis estimates the required rate of return on equity by

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12 http://www.valtrend.com/downloads/income/Empirical%20Support%20for%20Company%20Specific%20Risk.pdf

estimating the future yield of utility bonds and then adding the estimated risk premium.

Q. Please describe how the future utility bond yield was calculated.

A. To determine the future yield of utility bonds (i) the risk-free rate, and (ii) the bond spread over United States Treasury Bonds were added together. The applied risk-free rate in the Projected Risk Premium Analysis is the projected long-term government bond return of 2.92%, which was developed in the ECAPM analysis and is supported in Exhibit A-14 (TAW-1), Schedule D-5, page 2. The risk premium analysis calculations were performed separately for each of the bond rating spreads from A to BBB.

Q. Please discuss how the risk premium relative to utility bonds was determined.

A. One methodology to determine the risk premium would be to use the historical risk premium of utility stocks over utility bonds. Exhibit A-14 (TAW-1), Schedule D-5, page 9, column (h), shows that electric utility common stocks have an average historical risk premium of 4.37% (line 89) over the yields of A-rated utility bonds. However, an article published by the Federal Reserve, Exhibit A-126 (TAW-14), page 21, indicates that equity risk premiums in low interest rate environments are much higher than normal, which renders the application of historical data without additional adjustments inaccurate and unreliable. In fact, Staff acknowledged this fact in Case No. U-20479 (SEMCO Energy Gas Company's recent general rate case) noting, "the fact that in low interest rate environments the risk premium tends to be higher than usual. Although this is not traditionally a factor in Staff's methodology, the data backs this methodology."[13]

[13] Direct Testimony of Joseph E. Ufolla, MPSC Case No. U-20479 (September 27, 2019), page 36.

To adjust for the fact that risk premiums are higher when interest rates are low, the risk premium was calculated from the time the Federal Reserve began its recent accommodative period (2011 to 2018) when interest rates were held artificially low. During this period electric utility common stocks had an average risk premium of 6.91% over the yields of A-rated utility bonds. See Exhibit A-14 (TAW-1), Schedule D-5, page 9, line 91.

Q. What is the result of the risk premium analysis?

A. The Projected Risk Premium Analysis shows that the average ROE is 16.23% and ranges from a minimum of 15.39% to a maximum of 16.15%. These results are shown in Exhibit A-14 (TAW-1), Schedule D-5, page 4.

4. Comparable Earnings Analysis

Q. Briefly describe the comparable earnings analysis method.

A. Under this method, projected ROEs for the proxy group were analyzed. Earned ROEs for the proxy group are based on earnings per share and book value per share from Value Line. This information is readily available to investors. The actual results from this method are important in understanding the projected market expectations for the group. Exhibit A-14 (TAW-1), Schedule D-5, page 6, shows the results for the group of proxy companies by year for the 2022 through 2024 period. The average projected earned ROE for the proxy group is 10.36% and ranges from a minimum of 8.43% to a maximum of 12.58%.

Q. Why was this method included as part of the ROE analyses?

A. The earnings of a regulated utility are driven to a large extent by the equity book value since most utilities are authorized an earning level based on the book value of equity. As indicated above, the comparable earnings analysis calculates an ROE for the proxy group based on the ratio of earnings per share to projected book value per share using information that is available to investors. This is the same as the cost of equity for a regulated utility and provides a reasonable proxy of analyst and investor expectations for a regulated utility return. Given that earnings in any single year can vary from the authorized ROE, results for multiple years need to be kept in mind while determining the cost of equity capital using this method.

Q. Has the Commission previously commented on the use of the comparable earnings analysis?

A. Yes. In Case No. U-16794, the Commission specifically considered and gave weight to use of the ROE calculated using Value Line book value and earnings.

Q. Has any other jurisdiction given weight to the comparable earnings analysis?

A. Yes. Not only have they given weight to the analysis, the Virginia State Corporation Commission ("VSCC") is required by statute (Virginia Code, section 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in the region, which establish lower and upper boundaries for the allowed ROE.[14]

5. DCF Analysis

Q. Briefly describe the DCF model.

A. The DCF model, which is a type of income model, was developed by John Burr Williams and elaborated by Myron J. Gordon and Eli Shapiro. It was initially employed as a method of valuing the price of common stock by discounting future cash flows by the cost of capital. In its simplest form, this model can be used to estimate the required cost of equity

[14] In orders issued on November 7, 2018, and November 30, 2011, in Case Nos. PUR-2018-00048 and PUE-2011-00037, for example, the VSCC established the allowed ROE for Appalachian Power Company based on the earned returns on book value for a peer group of other electric utilities.

capital for a dividend paying stock with an assumed constant expected growth rate to perpetuity. This is generally projected as follows:

Equation (2): $K_e = (D_1 / P_0) + g + F$

Where:

D_1	=	D_0 x (1 + g);
K_e	=	annual required cost of equity capital;
D_0	=	current annual dividend;
D_1	=	annual dividend at the end of the first year;
P_0	=	current stock price;
g	=	expected growth rate; and
F	=	flotation cost adjustment.

This application of the model is displayed on Exhibit A-14 (TAW-1), Schedule D-5, page 5.

Q. What is the theoretical basis underlying the DCF model?

A. The DCF model is based upon an analysis of publicly-traded common stock. The DCF theory holds that an investor who agrees to purchase common stock at a given market price is purchasing the rights to an income stream. That income stream includes the present and anticipated earnings, the portion of those earnings that are currently and prospectively being paid to investors in the form of dividends, and the proceeds of capital appreciation derived from the ultimate sale of the stock at some future market price.

Implicit in the investor's decision to buy is the assumption that the investor considers the magnitude of that income stream. This includes the rate at which those dividends are expected to grow and the expected future selling price of the stock. The investor also considers the quality or risk of that income stream; that is, the likelihood that expectations will, in fact, be realized.

Based upon all these considerations, the investor agrees to pay a given market price for the stock at a given moment in time. Presumably, that market price represents the present value of that anticipated income stream, including dividend and price appreciation, at some discounted rate. This can be expressed as follows:

Equation (3): $P_0 = D_1/(1+K_e)^1 + D_2/(1+K_e)^2 + \ldots + D_n/(1+K_e)^n + P_n/(1+K_e)^n$

Here, the value of the future anticipated stock price (P_n) and dividends (D_1, $D_2 \ldots D_n$) are discounted based upon the perceived risk of the investment (K_e). Note, however, that even the future stock price (P_n) becomes a function of anticipated dividend appreciation so that, ultimately, the price of the stock today is a function of the present value of growth of the dividend stream to infinity.

The standard annual form of the DCF model presented in Equation (2) above can be referred to as the dividend growth model. It is equal to the expected dividend yield (D_1/P_0) plus the expected rate of growth in dividends (g) plus the flotation cost adjustment (F). The model assumes an annual dividend payment and that dividends, earnings, book value, and price per share grow at the same constant annual rate over time.

Q. Please explain how the dividend yield was calculated.

A. In theory, the DCF method calls for the "spot dividend yield" that is anticipated by investors at the time the required cost of equity capital is determined. Consequently, the theoretical yield would be calculated by dividing the expected annual dividend by the most current stock price. However, spot stock prices are subject to short-term market fluctuations, and an average price is more reliable and more typically applied. As a result, an average of 30 daily closing stock prices covering the period November 18, 2019, through December 31, 2019 was used.

Q. How was the dividend yield for each of the proxy companies determined?

A. For each of the proxy companies, the average closing stock price for the period identified above was first determined. This provided an estimate of P_0. Then, the latest annual dividend amount was obtained. The annualized dividend was then divided by the average stock price (P_0) to determine the current dividend yield. The annualized dividend was determined by multiplying the latest quarterly dividend payment amount by four. Next, the current dividend yield was adjusted by multiplying by one plus the growth rate to obtain the expected dividend yield. The expected dividend yield is based on the expected dividend at the end of the first year (D_1) versus the current dividend (D_0). This process was repeated for each of the proxy companies. The stock average prices, dividend amounts, and dividend yields are shown on Exhibit A-14 (TAW-1), Schedule D-5, page 5.

Q. How was the growth rate for the DCF calculations determined?

A. One of the difficult steps in applying the DCF model is determining the appropriate growth rate. The DCF analysis should utilize, whenever possible, a single "long-term" (i.e., perpetual) <u>dividend</u> growth rate of the company required by the investors who own the company's stock. However, analysts do not typically provide long-term growth for dividends and, therefore, analyst projections for dividends over the next three years were used to estimate dividend growth. In addition to analyst dividend growth, company management will often provide guidance for projected growth and, therefore, two methods of analysis were performed: the first utilized consensus analyst dividend per share growth estimates, and the second utilized the mid-point of company long-term growth guidance. However, Staff and intervenors have been critical of the company guidance DCF as inappropriate in the past. While the Company disagrees with the assertions that have been made, calculations of both methods were done, and the analyst guidance DCF methodology was the only one considered in forming the Company's recommended ROE range in this case. For reference, the company guidance DCF can be seen in Exhibit A-132 (TAW-20), page 2.

Q. Why was dividend growth instead of earnings growth used as an input to your analysis?

A. The use of dividend growth is consistent with the fundamental basis of the model, as validated by the original paper, *Capital Equipment Analysis,* from Gordon and Shapiro.

This paper is included as Exhibit A-131 (TAW-19), and page 5 of the exhibit makes very clear the intent of the original authors:

> Translated, this means that the rate of profit at which a share of common stock is selling is equal to the current dividend, divided by the current price (the dividend yield), plus **the rate at which the <u>dividend</u> is expected to grow**. [Emphasis added.]

Q. What were the results of the DCF cost of equity analyses for the proxy companies?

A. Exhibit A-14 (TAW-1), Schedule D-5, page 5, shows the results for the Company's group of proxy companies. Proxy group company returns for the Analyst Consensus DCF ROE have a wide range from 7.15% to 11.84% with an average return of 9.35%.

Q. Why was a company guidance DCF calculated in addition to analyst estimates?

A. The DCF model works well if the Company is able to determine a single "long-term" (i.e., perpetual) growth rate. The mid-point of company guidance for growth since this encapsulates a single "long-term" growth rate was used. Analyst estimates often tend to focus on the near-term (i.e., growth rates for the next year or two years) instead of the long-term growth rate required for the model. This results in understating true investor-required returns in the current environment, where investors may accept lower growth in the near term but expect higher growth in the long term. Furthermore, different analysts may determine the basis for growth differently (i.e., excluding transitory effects such as one-time losses or gains); therefore, using Company guidance provides a more consistent and potentially more accurate approach to convey a single long-term growth expectation. Exhibit A-132 (TAW-20), page 2, shows the results for the Company's group of proxy companies. The returns for the Company Guidance DCF ROE also have a wide range from 8.76% to 10.44% with a very similar average return of 9.34%. However, as stated above, while the analysis was performed, and is informative, reliance was not placed upon the company guidance DCF to form the Company's recommendation in this case.

Q. Was any additional DCF analysis performed?

A. Yes. The DCF analysis was performed using dividend growth estimates from analysts. The use of dividend growth is consistent with the fundamental basis of this model, as validated by the original paper, *Capital Equipment Analysis,* from Gordon and Shapiro, the very same work that Staff continues to cite in their analysis. However, because of Staff's preference for an earnings growth based DCF, one was included in Exhibit A-132 (TAW-20), page 3. An application utilizing earnings growth for a DCF should also apply earnings yield rather than dividend yield in the calculation, and the Company's supporting analysis shows this as well. This application results in an average estimated ROE of 9.81%, a full 46 basis point increase over the dividend growth DCF included in the analysis.

Q. Does the result of the DCF analysis fully reflect the cost of equity required for utilities?

A. No, it does not. The reliability of the DCF, considering the low yields on bonds, including United States Treasury bonds, provides less confidence than a mechanical application of the DCF and produces a risk-appropriate ROE, as required by *Hope* and *Bluefield*. The DCF results can be compared against both the ECAPM, Risk Premium, and Comparable Earnings, and can be viewed as an outlier. Further, using an ROE of 9.35% and the Company's recommended equity ratio of 52.5% would result in an FFO-to-Debt of 18.5%, which would further deteriorate the Company's credit.

The DCF analysis provides output of two companies with ROEs less than 8%. No commission in the country has authorized an ROE less than 8%. This disparity highlights why regulators such as FERC have had concern with relying so heavily on the DCF model. The average output of the DCF analysis, which is below the national average ROE as reported in the RRA report, would not provide sufficient risk premium to fairly compensate investors for the risks associated with owning the stock, particularly because equity owners have the lowest claim to Company assets and income. The Commission has already noted in Case No. U-20322 that an ROE of 9.65% is too low[15] and, because the resulting average of the DCF clearly underestimates the required ROE, the Company's ROE recommendation considers the full range of results provided by the ECAPM, CAPM, DCF, Risk Premium, and Comparable Earnings analyses.

III. DISCUSSION OF EMPLOYEE INCENTIVE COMPENSATION PLAN FINANCIAL INCENTIVES

Q. Are there additional topics you would like to address with your direct testimony?

A. Yes. Specifically, I would like to address the financial metrics included in the EICP as presented by Company witness Amy M. Conrad.

[15] MPSC Case No. U-20322, September 26, 2019 Order, page 72.

Q. Do the financial measures in the Company's proposed EICP provide tangible benefits to customers?

A. Yes. Including financial measures as part of the performance measures in the Company's EICP provides customers with both qualitative and quantitative benefits. A financially healthy utility benefits customers in part through lower funding costs which reduce electric bills as highlighted above and helps to provide customers with better service. As stated earlier, a virtuous cycle is created by constructive regulation, which creates a financially healthy utility capable of attracting capital, which it then invests in order to improve customer experience/service. It is not simply enough for a utility to have the <u>opportunity</u> to earn a fair return – in order to attract capital, the management and employees must actually <u>achieve</u> results. The inclusion of financial measures in the Company's incentive compensation plans ensures that employees are incented to achieve results which benefit customers as well as attract capital. Additionally, financial performance is required to maintain healthy credit ratings – if the Company were to not meet certain financial measures, it would lead to credit degradation of the Company which would in turn result in higher interest costs being borne by the Company. Because of these dynamics, including financial incentive measures in the EICP provides appreciable benefits to Consumers Energy's customers.

Q. Please discuss the role both Earnings and Operating Cash Flow ("OCF") plays in maintaining the Company's credit.

A. The amount and perceived stability of Consumers Energy's OCF, which is one of the financial measures in the Company's EICP, are vital metrics directly observed by credit rating agencies and are reflected in their annual assessments of the Company's credit quality. Given the Company is investing a significant amount of capital and, therefore, raising substantial debt, the Company's ability to achieve stated OCF goals, which is driven primarily by the Company delivering stated earnings, is a key factor in determining its credit ratings and ultimately attracting investment to achieve lower cost of capital. Customers, therefore, have a strong vested interest in the Company maintaining attractive debt pricing. As discussed earlier and shown in Exhibit A-14 (TAW-1), Schedule D-5, page 7, the Company has saved ratepayers $88 million *annually* as a result of improved credit ratings and lowered interest costs. Incentivizing employees to achieve both Earnings and OCF targets is critical to maintain ratings and provides tangible benefits to customers.

Q. Is OCF a duplicative financial measure to EPS?

A. No. While earnings and cash flow are related, they are not the same. EPS is a measure of profit generated by a company's daily operations. The figure includes revenues and expenses. Some of the expenses used to calculate earnings are considered "non-cash" items, such as depreciation and amortization, and do not impact cash flow. Moreover, select financing decisions made by the Company such as issuing or repurchasing stock can have a direct impact on EPS without impact to OCF. OCF is a measure of cash generated from operations and is necessary to make investments in the utility. The cash flow measure in the incentive plan starts with generally accepted accounting principles OCF, and it is then adjusted as discussed in Ms. Conrad's direct testimony.

Q. Does this conclude your direct testimony?

A. Yes.