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November 9, 2018

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

RE: Case No. U-20134 – 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.

Dear Ms. Kale:

Enclosed for electronic filing in the above-captioned case, please find the **Initial Brief of Consumers Energy Company**. This is a paperless filing and is therefore being filed only in a PDF format. I have enclosed a Proof of Service showing electronic service upon the parties.

Sincerely,

Bret A. Totoraitis

cc: Hon. Sharon L. Feldman, Administrative Law Judge
Parties per Attachment 1 to Proof of Service

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-20134

INITIAL BRIEF OF CONSUMERS ENERGY COMPANY

November 9, 2018

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-20134

INITIAL BRIEF OF CONSUMERS ENERGY COMPANY

I. INTRODUCTION AND OVERVIEW

A. Procedural Overview

On May 14, 2018, Consumers Energy Company (“Consumers Energy” or the “Company”) filed its Application in this case, seeking an increase in its electric rates sufficient to produce additional revenues in the approximate annual amount of \$58 million.¹ As a result of adjustments made by the Company in response to issues raised in the testimony of the Michigan Public Service Commission (“MPSC” or the “Commission”) Staff (“Staff”) and intervenors, this request has subsequently been reduced to approximately \$44 million annually. See Appendix A, line 10, column (e).

Evidentiary hearings in this case commenced October 11, 2018, and concluded on October 18, 2018. The record in this case consists of 3,630 pages and hundreds of exhibits. Pursuant to the schedule established by the Administrative Law Judge (“ALJ”), initial briefs are

¹ The Company’s current tariffs also include a monthly credit (Credit A) to customers’ bills to reflect a reduction in federal income tax expense and tax gross-up factor that was enacted after the close of the record in the Company’s last electric rate case, Case No. U-18322. The Company’s Credit A reflects a reduction of the revenue requirement calculated in Case No. U-18322 of approximately \$113 million. See July 24, 2018 Order Approving Settlement Agreement, MPSC Case No. U-20102. Credit A will terminate with the final order in this case.

due November 9, 2018, and reply briefs are due November 21, 2018. A Proposal for Decision target date is set for December 21, 2018.

B. Executive Summary/Overview Of Company Requests

Company witness Michael A. Torrey provides an overview of the Company's request in this case. 2 TR 54-93. The \$58 million of annual rate relief originally requested by the Company in this case is primarily driven by the Company's need to serve its customers and the Company's continued significant investment in Michigan. 2 TR 62. Mr. Torrey testified that the Company expects to make about \$18 billion of capital investments over the next 10 years and that electric investments account for approximately 55% of that total. 2 TR 62. Mr. Torrey identified five main categories of investments that the Company has made, and continues to make, to improve the value of the services the Company provides to its customers since rates were established in the Company's last electric rate case, Case No. U-18322. These include investments to ensure generation supply and distribution system reliability, protection of the environment, enhanced technology, employee incentive compensation, and electric vehicles ("EVs"). 2 TR 62-74.

Mr. Torrey testified that the Company's investment decisions are driven by Consumers Energy's goal of improving customer value, customers' satisfaction with their utility service, and all aspects of the customer experience. 2 TR 55-61. Consumers Energy is highly engaged in listening and responding to its customers' preferences and concerns, both through the informal contacts that the Company makes with its customers on a day-by-day basis, and also through more formal and deliberate methods such as focus groups and quantitative survey research. 2 TR 57. Mr. Torrey testified that the primary external benchmark of customer satisfaction used by

the Company is J.D. Power survey data. 2 TR 57. He testified that Consumers Energy uses the J.D. Power survey results as a guide for improvement. 2 TR 58.

“We identify the relative importance of each attribute and driver and compare our performance to that of our benchmark companies This allows us to prioritize activities based on their relative importance to overall satisfaction and our comparative level of performance.” 2 TR 58.

Mr. Torrey further testified:

“With the rich data set that J.D. Power provides, there is no longer the need to speculate about what truly drives customer satisfaction. This independent assessment provides a data-driven and analytical basis for making investment decisions and process improvements that positively impact customer satisfaction. Thus, decisions on where to invest resources are driven by what provides the greatest value to our customers, based not upon our opinions or hypotheses, but rather through direct customer feedback.” 2 TR 59.

As a result, the survey data has shown that this customer-focused investment planning has worked as intended to increase the customers’ sense of value regarding the service that Consumers Energy provides to them. In general, the Company has been experiencing a trend of improving customer scores for both of its customer segments since 2011. 2 TR 59-60. In 2017, the Company’s residential customer satisfaction scores were in the top third for the Customer Satisfaction Index, only two points away from being in the first quartile. 2 TR 59. Based on year-to-date results for 2018, after three of four survey waves, not only is Consumers Energy in the top third, but also in the top quartile. 2 TR 59. For business customer satisfaction, Consumers Energy’s 2011 score showed a gap of 52 points compared to other top companies in the region. 2 TR 59. However, in 2017, that gap has narrowed to only 18 points – a 65% improvement. 2 TR 60. In addition to J.D. Power surveys, Consumers Energy utilizes a benchmark study from TQS Research Inc. (“TQS”), an independent research firm, to gather customer feedback for large electric customers with demands greater than 1 MW. 2 TR 60.

Mr. Torrey testified that, in 2017, over 89% of Consumers Energy business customers surveyed in the TQS study said they were very satisfied, ranking the Company as the sixth best electric service holding company in the nation. 2 TR 60.

The Company's original filing in this case also includes an increase in total Operating and Maintenance ("O&M") expense of \$19 million when compared to current rate levels. 2 TR 74. Mr. Torrey testified that the Company proactively seeks out opportunities to minimize increases in O&M expenses. 2 TR 76. Mr. Torrey described a number of examples of the efforts Consumers Energy has made to minimize O&M expense increases. Among other examples, those efforts include: (i) improvements in employee safety, which impacts costs by reducing employee medical claims and lost work days (saving approximately \$7.2 million annually); (ii) an initiative to improve distribution reliability by reducing annual average outage minutes from 2006 through 2017 with economic benefits to customers in excess of \$28.3 million; and (iii) reductions in costs related to Other Post Employment Benefit ("OPEB") plan changes. 2 TR 76. Mr. Torrey testified that the Company has achieved the ranking of third lowest administrative and general costs on a cost-per-customer basis for electric companies with more than 500,000 customers. 2 TR 76.

Staff's position in this case indicates an initial revenue sufficiency of approximately \$44 million on a jurisdictional basis. Exhibit S-1, Schedule A-1. However, Staff's filing also includes a recommendation to disallow \$3.4 million of the Company's proposed marketing costs for the new residential summer on-peak rate that was not incorporated into Staff's revenue sufficiency calculation. 6 TR 2424. As a result, Staff's filed position actually reflects a revenue sufficiency of \$47.4 million. Appendices A through F attached to this Initial Brief show, in

summary form, the Company's initial position, Staff's as-filed position, the Company's Initial Brief position, and the variance between the Company's and Staff's positions.

The Company disagrees with many of the proposals included in the testimony filed by Staff and the intervenors in this case. The Company, in this Initial Brief, addresses several anticipated areas of dispute and relies upon the record and evidence in support of its requested rate relief. As discussed below, the record evidence in this case supports final rate relief in the annual amount of approximately \$44 million, including a 10.75% Return on Equity ("ROE"), authorization to implement an Investment Recovery Mechanism ("IRM") for reconciliation in calendar years 2020 and 2021, and approval of all of the other various requests included in the Company's filings. All other parties' arguments to the contrary should be rejected, and the Commission should issue an order granting the Company's requested relief in full.

II. TEST YEAR

In each rate case, a test year must be selected. 2008 PA 286 specifically permits the use of "projected" test years in setting utility rates. MCL 460.6a(1). Consumers Energy used a projected 12-month test year ending December 31, 2019 for determining final rate relief. 2 TR 324. In developing projected test year data, Consumers Energy began with a 2017 historical period (2 TR 317-324), which was then adjusted to reflect updated sales and projections of investments, expenses, and revenues.

III. RATE BASE

A. Net Utility Plant

1. Distribution Capital Expenditures

On February 28, 2017, in Case No. U-17990, the Commission issued an Order ("February 28, 2017 Order") in the Company's electric rate case, which in part, directed the Company to submit a five-year electric distribution investment and maintenance plan to Staff

detailing anticipated needs, priorities, and projected spending for the Company's High Voltage Distribution ("HVD") and Low Voltage Distribution ("LVD") systems. In response to the February 28, 2017 Order, the Company developed its Electric Distribution Infrastructure Investment Plan ("EDIIP"). The Company conducted a thorough review of the business practices of each internal department involved in the planning of HVD and LVD capital investments, and developed robust explanations of how it identifies HVD and LVD investment needs, how it develops engineering solutions to address those needs, and how the resulting projects are prioritized to maximize the benefits delivered with available funding. 2 TR 162. Additionally, the Company reviewed its financial planning process to consider how funding is made available to address HVD and LVD capital needs. 2 TR 162. Then, the Company engaged in a coordinated effort among HVD and LVD engineering personnel, financial planning personnel, strategy personnel, and others to develop five-year spending plans for numerous HVD and LVD capital and O&M programs. These investment and maintenance plans are described in detail in Exhibit A-111 (TJS-1).

The EDIIP provides the Company's investment logic when determining HVD and LVD spending, and provides the Commission with detailed information to help evaluate the Company's proposals. The EDIIP also shows how the proposed 2019 HVD and LVD spending in this case fits into the Company's longer-term HVD and LVD planning. 2 TR 163. Company witness Timothy J. Sparks explained:

“[t]he Company's capital spending plan directly aligns with the Governor's 2013 reliability goals to reduce the frequency and duration of customer outages. The Governor's guidance is for utilities to be operating in the first quartile for System Average Interruption Frequency Index ('SAIFI') among peers and in the top half for System Average Interruption Duration Index ('SAIDI') among peers. The EDIIP is the Company's plan to achieve what Governor Snyder laid out in 2013. In order to achieve first quartile

SAIFI and second quartile SAIDI by 2022, the Company must increase spending in reliability programs. The Company's capital spending plans are a reflection of that increase in capital spending in order to improve the reliability of the Company's electric system to levels that align with the Governor's goals." 2 TR 177.

The Company's 2019 projected investments are a part of the glide path through 2022, set forth in the Enhanced Infrastructure Replacement Program ("EIRP"), that will enable the Company to achieve the 120 minute System Average Interruption Duration Index ("SAIDI") target.

Staff witness Tayler Becker expressed concern that the Company established spending amounts in the EDIIP and identified specific projects to align with estimated project costs in the EDIIP. 6 TR 2381-2382. The concern is unwarranted and it is reasonable that the costs in the EDIIP would align with the rate case projections. The EDIIP's purpose is to provide a longer-term look at utility distribution investment planning and a more thorough understanding of anticipated needs, priorities, and spending than what can be provided in the context of single-year electric rate cases. 2 TR 178. The EDIIP was submitted to the Commission on March 1, 2018 in Case No. U-17990, the Company's 2016 electric rate case, and this case was filed on May 14, 2018. Based on these dates, it is evident that the two filings were being developed at around the same time. Therefore, it is reasonable that projected spending in 2019 would align. More importantly, the 2019 distribution spending in both filings is based on the same plan and the Company carefully considered future needs for the distribution system then developed spending projections based on the costs of meeting those needs. 2 TR 178.

a. Company's Position

The Company's electric distribution system consists of two major electric subsystems: HVD and LVD systems. The 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. Company witness James R. Anderson, Executive Director of Electric Transmission, supported

the Company's capital and O&M spending related to the HVD system, which consists of three distinct networks: (i) the HVD substations; (ii) the HVD lines; and (iii) the LVD substations. 5 TR 1839, 1841. The Company's LVD system is comprised of 66,763 total miles of lines, with 56,098 of those miles being overhead, and 10,665 being underground. The LVD system consists of 13 different voltages due to acquiring several distribution systems from smaller distribution companies over its history. 4 TR 1135. Company witness Andrew J. Bordine, Executive Director of Grid Infrastructure, supported the Company's LVD system. 4 TR 1134. As shown in Exhibit A-12 (AJB-1), Schedule B-5.4, the total electric distribution capital expenditures that the Company is requesting rate recognition of for the years 2018 and the 12 months ending December 31, 2019 are in the amounts of \$507,191,000 and \$568,723,000.

In developing the projected spending amounts, the Company follows a comprehensive and continuous improvement approach of analyzing the state of the electric distribution system. This includes an evaluation of the electric distribution grid at the system-wide, regional, and circuit-level performance. Electric distribution spending is then balanced across two broad categories: (i) spending responding to the immediate needs of customers through new business connections, relocation of assets, and response to emergent system needs; and (ii) spending to improve the overall reliability of the electric distribution system by enhancing and replacing infrastructure, upgrading equipment capacity, and laying the foundation for advanced grid capabilities. 4 TR 1135-1137; 5 TR 1844.

b. Areas Of Dispute With Staff

For many of the proposed adjustments made to the Company's electric distribution capital spending level, Staff witness Becker recommended capital spending levels based on inflation. However, the inflation rates used were inconsistent, not supported, and never explained. For the HVD New Business Program, Mr. Becker recommended capital spending be

held to an average actual spending, for the years 2014, 2015, and 2017, adjusted for Staff's inflation. 6 TR 2386. Mr. Becker never states what the inflation factor is for this program; however after a review of Exhibit S-14.0 (TJB-1), the inflation rate appears to be 4.64%. 5 TR 1954. For the Company's HVD Lines Reliability Program capital spending, Mr. Becker recommended that the capital spending level be held to the 2018 projected bridge year level, adjusted for Staff's inflation. 6 TR 2394. After a review of Exhibit S-14.1 (TJB-2), it appears that an inflation factor of 2.23% was used for this program. 5 TR 1955. For the LVD Substation Reliability Program, Staff witness Becker applied "Staff's inflation" to determine both 2018 projected bridge year and 2019 projected test year spending. 6 TR 2395. Considering Exhibit S-14.1 (TJB-2), line 3, this computes to an inflation factor of 2.28% for 2018 and 2.23% for 2019. 5 TR 1955. Without explanation, Staff did not apply any inflation to the Substation Communication Upgrades sub-program. And, Staff witness Becker applied inflation factors of 50% for 2018 in Electric Operations Other capital spending, plus 25% in 2019. 5 TR 1955.

The Company undertook a similar review of the inflation factor applied to a number of the Company's LVD programs and subprograms. For LVD New Business Program, Staff witness Becker recommended that capital spending be held to the average actual spending in 2015 through 2017, adjusted for Staff's inflation. 6 TR 2384. After reviewing Exhibit S-14.0 (TJB-1), Staff appears to have applied an inflation factor for this sub-program of 6.59%. 4 TR 1277. For the LVD Lines Reliability projected spending plan for 2018 projected bridge year and 2019 projected test year, Mr. Becker recommended that the spending level be held to the five-year average actual spend levels (2013-2017), adjusted for Staff's inflation. 6 TR 2391. Considering the numbers in Exhibit S-14.1 (TJB-2), an inflation factor of 2.28% for 2018 and 2.23% for 2019 was utilized. 4 TR 1278. For the Grid Capabilities: Automation sub-program,

Mr. Becker recommended 2017 actual spend plus 50% in 2018, adjusted for Staff's inflation. 6 TR 2401. Considering Exhibit S-14.1 (TJB-2), this arithmetically works out to an inflation factor of 50% for 2018 and 2.23% for 2019. 4 TR 1278. For the Grid Capabilities: Advanced Technologies sub-program, Mr. Becker recommended that the expenditure level be adjusted to the 2018 projected bridge year spend, adjusted for Staff's inflation. 6 TR 2401. Based on Exhibit S-14.1 (TJB-2), an inflation factor of 2.23% for 2019 expenditures was applied. 4 TR 1278. Similar inconsistencies were made in the development of the expense levels Demand Failures Program and Electric Operations Other. See 4 TR 1279-1280.

The Company undertook this review to demonstrate the general inconsistency of Staff's recommendations. While appearing to base its recommendations on historical spending, adjusted for inflation, this ultimately is inaccurate. In his testimony, Staff witness Becker never provided the inflation rates used, never explained how the inflation rates were determined, and never provided the necessary calculations for determining the inflation rates. The inflation factors effectively vary from 0% to 50% without explanation of why they are different among the sub-programs, nor of why the inflation factors chosen for each particular sub-program are appropriate for each respective sub-program. 5 TR 1955. Ultimately, the inflation rates utilized appear to be arbitrary and no explanation for the reasonableness of this approach was provided. In addition to these concerns, the Company disagrees with the support provided for Staff's proposed adjustments. Specific concerns related to proposed capital spending reductions are discussed below.

(i.) HVD New Business Program

The HVD New Business Program consists of the capital costs to meet the needs of large Commercial and Industrial ("C&I") customer new business requirements that are too energy-intensive to be served by the area LVD system. 5 TR 1842. The typical program

investments include dedicated substations and interconnections of dedicated substations to the HVD system with poles, conductors, and metering to connect new industrial customers. *Id.* The Company is projecting HVD New Business Program capital expenditures in the amount of \$13,572,000 in 2018 and \$10,000,000 for the 2019 projected test year. See Exhibit A-18 (JRA-3), line 1, columns (c) and (f), respectively. Staff disagreed with the Company's projections and argued that the HVD New Business Program projected spending plan should be held to the three-year average actual spend levels (excluding 2016 actual spend), adjusted for Staff's inflation as shown in Exhibit S-14.0 (TJB-1), line 2, column (i). 6 TR 2386. The Commission should not adopt Staff's proposed expenditure reductions.

The Company based its projected capital spending for the HVD New Business Program based on both known projects and expected expenditures as determined by historical spending levels. 5 TR 1848, 1956. This methodology allows the Company to be able to respond to customer inquiries that arise and are required for new businesses in the 2019 test year. 5 TR 1956. As shown in Exhibit A-17 (JRA-2), line 1, the Company's five-year average spending level for 2013 through 2017 is \$11,144,000.

In recommending the use of a three-year average for these expenditures, Staff does not discuss why a three-year average is an appropriate means for determining the Company's spending level. 5 TR 1956. And while Staff indicated that it chose to exclude 2016 actual spend because it considered the spending that year to be uncharacteristic (6 TR 2386), Staff did not provide any basis explaining why this spending should be considered uncharacteristic nor why it would be appropriate to exclude a year of actual spending in a three-year average simply because one particular year was higher. 5 TR 1956. By its very nature, the use of spending averages smooths variability. Staff's adoption of a three-year average would have smoothed the higher

spending in 2016. Moreover, the 2016 spending amount is important to highlight as it shows there is always some variability in the lead-time and timing of commitment from customers, which affects when the HVD New Business work is scheduled, and when the Company will be committed to incur expenditures. 5 TR 1957. For this reason, the Company used a five-year average to inform its 2019 projected spending level.

In recommending the adoption of a three year average, Staff witness Becker expressed additional concern with the Company's projected spending indicating that a portion of the spending is still undetermined and alleging that the Company projected this expenditure amount to match the EDIIP. 6 TR 2386. As an initial matter, the EDIIP does not create financial targets for the Company, and this case has not been designed to simply hit those financial targets. Company witness Anderson testified, "This characterization is inaccurate and fails to take into account that when developing the EDIIP, the Company carefully considered future needs for the distribution system, and then developed spending projections based on the costs of meeting those needs." 5 TR 1958. While understanding Staff's concern about the undetermined spending, the amount of time required to move from a completed customer agreement to final construction can vary significantly, and it is reasonable that some projects for 2019 will not have been identified or fully committed to at this point in 2018. 5 TR 1957. This is the nature of this program, and is why the Company considers both known projects and historic actual spending to project spending for the test year. 5 TR 1957. Additionally, the Company has identified additional HVD New Business projects for potential construction in 2019. One example is a proposed \$2.8 million project, consisting of a new dedicated customer substation and a 0.1-mile 138 kV line to serve two new milk processing facilities near St. Johns. Over the course of a year, new

projects can emerge, even in the later parts of the year. This reinforces why the Company considers both known projects and historic actual spending to develop reasonable projections.

Therefore, the Company requests that the Commission approve the Company's projected spending level for the HVD New Business Program.

(ii.) HVD Lines Reliability

The HVD Reliability Program includes asset management programs that are designed to ensure the long-term safe and reliable operation of the electric distribution HVD system. 5 TR 1848. The HVD Lines Reliability sub-program includes overhead line rebuilds, pole top rehabilitation, underground line replacements, and pole and tower replacements. 5 TR 1849. For the HVD Lines Reliability sub-program, the Company is projecting capital expenditures of \$36,672,000 for 2018 and \$38,837,000 in 2019. Exhibit A-19 (JRA-4), line 1, column (c), and line 1, column (f), respectively. The HVD Lines Reliability work undertaken in the projected test year will be predominantly directed at: (i) completing overhead line rebuilds including insulator, conductor, cross-arms, and structure replacements; (ii) pole-top rehabilitation, which includes replacing deteriorated cross-arms, insulators, and poles; and (iii) pole and tower replacements. Additionally, as part of HVD Line Rebuild and Pole Top Rehabilitation projects, the Company clears the rights of ways and addresses hazard trees. These projects are initiated to upgrade assets in order to reduce the number of outages due to deterioration and lightning and to improve the ability to withstand storm activity. 5 TR 1860.

Staff proposed adjusting the Company's HVD Lines Reliability capital spending to the 2018 projected bridge year spending level, plus inflation. In Staff witness Becker's review of the Company's expenditure amount, Mr. Becker argued that the Company should have included more of the 10 worst-performing circuits identified in Exhibit S-14.4 (TJB-5), page 16, which is Attachment A to discovery response 20134-ST-CE-368, in the Company's 2019 list of rebuild

and rehabilitation projects. This argument fails to recognize that Staff requested that the Company provide the worst performing lines from 2015 through 2017, excluding tree-related incidents. Mr. Anderson explained that the reason more of these lines were not identified on the Company's 2019 list of rebuild and rehabilitation projects is that the Company already prioritized some of these lines and addressed them prior to the projected test year. Specifically, since 2015, the Company has already completed work on the Gun Lake, McBain, Waldron, Nashville, Galesburg, and Lake Shore lines. See 5 TR 1961. Exhibit A-120 (JRA-15) provides a more comprehensive list of the capital projects completed on these lines since 2015. Additionally, the Company has already undertaken projects on the Niagara, Hudsonville, and Davison/Dort 46 kV lines, which were among the worst-performing lines in the 2015 through 2017 timeframe. 5 TR 1962. Thus, the reason more of the worst-performing circuits identified in Exhibit S-14.4 (TJB-5), page 16, were not on the Company's 2019 list of rebuild and rehabilitation projects is that the work either has already been completed or will be completed prior to the projected test year.

The Company reasonably selects what lines to address. This selection process uses the professional judgement of the Company's engineers and takes into account the line performance and line condition. 5 TR 1963. Exhibit A-24 (JRA-9), page 1, identifies the rebuild and rehabilitation projects to be undertaken during the projected test period. Company witness Anderson testified that these lines would have appeared farther down on the list provided to Staff in discovery, if the parameters of the discovery request were expanded. 5 TR 1963.

Staff also expressed concern with the amount of the projected average cost per mile. 6 TR 2393. Based on Exhibit S-14.4 (TJB-5), page 9, discovery response 20134-ST-CE-359, Staff indicated that the average cost to rehabilitate an HVD circuit in 2018 was approximately

\$44,000. After noting the Company's explanation for the higher costs, Staff witness Becker reasoned that "the project was also performed in the winter months which are typically months in which work takes longer to complete due to cold weather conditions, which generally means higher costs. It appears that the projected average cost per mile for rehabilitation work will not deviate as much as \$33,000 per mile given the reasoning provided in the discovery response and asserts that the 2019 projected average cost per mile is too high." 6 TR 2393. However, the Company's response in 20134-ST-CE-359, Exhibit S-14.4 (TJB-5), page 9, shows that actual 2018 HVD line rehabilitation costs per mile (covering a single project) were unusually low and that the Company's projected costs per mile would be higher.

To start, the 2018 cost per mile provided in Exhibit S-14.4 (TJB-5), page 9, discovery response 20134-ST-CE-359, reflects only a single project because that was the only HVD line rehabilitation project completed during Staff's specified time period. 5 TR 1966. A single data point is not a reasonable basis for assessing the Company's projected HVD line rehabilitation costs. Exhibit A-122 (JRA-17) shows a broader view by illustrating all HVD line rehabilitation projects completed in 2017 and year-to-date in 2018. As indicated on Exhibit A-122 (JRA-17), column (k), the average cost per mile in 2018 for HVD line rehabilitation projects are actually over \$75,000, which is in line with the Company's projections.

Company witness Anderson further explained why the average cost to rehabilitate an HVD circuit in 2018 was lower than the projected test year amount. Mr. Anderson testified:

- “• The HVD line rehabilitated in 2018 was a looped or networked (not radial) line, which allowed for the work to be completed in a de-energized condition. This allowed for work to progress at a faster pace than when the HVD line rehabilitation is performed on an energized line;
- “• The majority of the HVD line is located in farm fields with good access; and

- “• The rehabilitation work was performed in the winter months through the mid-April timeframe. Dry conditions prevailed in this case, which allowed for wheeled equipment to access farm fields, and crane mats were only needed to access a handful of pole locations.” 5 TR 1963.

Additionally, Mr. Anderson discussed the fact that completing a project during the winter does not necessarily raise costs as posited by Staff. In fact, winter does not have the same negative effect on HVD line rehabilitation as it does on some other kinds of projects, as this is overhead work. 5 TR 1964. To the contrary, working in winter can be helpful for pole top work as the more solid ground provides better support for the equipment performing this overhead work and mitigates the need for crane mats. 5 TR 1964. Environmental impacts are lessened. *Id.* Moreover, the HVD system experiences loadings during winter months that allow for components to more easily be removed from service so construction can be completed in a de-energized state. This allows work to be performed more quickly. 5 TR 1965. These factors ultimately have the impact of lowering customer cost for HVD line rehabilitation work.

The HVD lines system is the foundation of the Company’s distribution system, without which, the LVD system could not function. De-emphasizing HVD Lines Reliability spending because it only contributes to an average of 12% of the Company’s SAIDI minutes (6 TR 2393) is unreasonable. A significant portion of the HVD lines system is looped and allowing it to deteriorate would result in significant impacts on a much broader portion of the HVD system than just the line section that initially experiences an outage. 5 TR 1967. The Company reasonably invests in HVD Lines Reliability projects to ensure that the system does not deteriorate and prioritizes investment in the HVD lines where there have been customer interruptions. This is done to the benefit of customers.

(iii.) LVD Substation Reliability

The LVD Substation Reliability expenditures are directed at: (i) new or rebuilt substations; (ii) new mobile substations; (iii) animal mitigation; (iv) transformer replacements; (v) regulator replacements; and (vi) other targeted replacement programs for specific equipment, such as oil circuit reclosers and breakers, substation lightning arresters, and Spring-Operated Ground Switches. 5 TR 1863. The Company is projecting LVD Substation Reliability expenditures in the amount of \$19,273,000 in 2018 and \$20,202,000 in 2019. Exhibit A-19 (JRA-4), line 2, columns (c) and (f).

Staff witness Becker proposed adjusting the 2018 projected bridge year and 2019 projected test year spend amounts to the 2017 actual spend amount, adjusted for Staff's inflation. 6 TR 2395. To start, Staff's proposed adjustment to the 2018 bridge year expense is unsupported. Mr. Becker failed to provide any explanation for why the 2018 projected bridge year should be adjusted. Additionally, Mr. Becker did not identify any undetermined spending for LVD Substation Reliability in the 2018 projected bridge year. 5 TR 1970. All 2018 spending in this sub-program has identified projects. 5 TR 1970. Therefore, the Commission should reject the proposed adjustment for the 2018 projected bridge year for LVD Substation Reliability.

With respect to the Company's projected test year spend amount, Staff's primary reason for the proposed adjustment was that the Company had \$3,805,000 for animal mitigation projects and regulator replacement projects that was still undetermined as of August 2, 2018. 6 TR 2395. This reduced the Company's projected expenditure amount by \$5,446,000. However if the alleged undetermined spend was the basis for Staff's proposed adjustment, then the proposed reduction should have been limited to \$3,805,000. Moreover, the Company indicated that it planned to identify additional substations to receive animal mitigation over the course of the year

in 2018. This is a reasonable practice as gathering data throughout the year before finalizing the animal mitigation project list allows the Company to undertake projects at the highest priority substations. 5 TR 1968. The Company typically identifies many projects for the next year in the summer and fall timeframe of the current year. *Id.* Exhibit A-123 (JRA-18) provides updated information regarding additional animal mitigation projects. As shown in the exhibit, the Company has identified additional animal mitigation projects. The Company also indicated that it planned to identify additional substations to receive regulator replacements over the course of the year in 2018, in order to have the most current test results available. 5 TR 1968. Exhibit A-123 (JRA-18) provides updated information regarding additional regulator replacement projects. Therefore, as there is no longer any undetermined animal mitigation or regulator replacement project spending, the Commission should approve the Company's projected LVD Substation Reliability capital spending.

Additionally, Staff expressed concern about the projected average spend for animal mitigation installed to upgrade to the Company's current substation animal mitigation standards. Staff witness Becker indicated that the average cost for each substation in 2018 was approximately \$64,000 for 11 substations which received the animal mitigation upgrades in 2018 and average cost of the substations to be mitigated in the projected test year is \$100,000. 6 TR 2394. However, Staff's average spend amount failed to take into consideration the projects undertaken. Of the 11 substations evaluated by Staff where animal mitigation installations had been completed, two of those projects consisted only of adding partial animal mitigation items to substations that already had a portion of the present standard animal mitigation measures previously installed. This resulted in a lower average animal mitigation costs for those particular substations. 5 TR 1969. Further, Company witness Anderson testified that "[t]he Company has

now completed animal mitigation projects at 24 substations year-to-date in 2018. With this larger data set, the average cost for each substation in 2018 is approximately \$75,300, reducing the apparent gap identified by Mr. Becker.” *Id.* And, if the average cost of these projects continued to average approximately \$75,300, then the Company could accelerate its installation plans, advancing efforts to reach the goal of having animal mitigation at all the general LVD substations. 5 TR 1970. Therefore, the Commission should approve the Company’s projected spend amount for LVD Substation Reliability.

(iv.) Substations Communications Upgrades

The Substations Communications Upgrades sub-program allows for the upgrade of end-of-life telecommunications networks currently providing Supervisory Control and Data Acquisition (“SCADA”) functionality at the Company’s substations. 5 TR 1885. The Company’s telecommunications service provider has indicated that it will sunset their analog technology in the near future, which causes the Company to replace the existing analog multi-drop circuits at 230 substations with dedicated high-speed, open standards-based communications and modern cybersecurity due to a diminishing level of service provider support for the analog technology. *Id.* The Company is projecting Substations Communications Upgrades expenditures in the amount of \$23,000,000 in 2018 and \$41,000,000 in the projected test year. Exhibit A-19 (JRA-4), line 5.

After noting the reasoning for the Company’s proposed expenditure amount, Staff proposed adjusting the expenditures indicating concern with the Company’s ability to spend these levels of increases. 6 TR 2396. However, this concern is unwarranted. The Company has a comprehensive plan to complete all work in the Substations Communications sub-program within the projected years. A dedicated project management team is in place to ensure contractor performance and project success. 5 TR 1970. The engineering design work has already been

identified, scoped, and contracted, with approximately 60% of the designs complete. Additionally, approximately 90% of all material for remaining work in 2018 and 2019 has been purchased or has a procurement contract in place. 5 TR 1971. The Company has three contracted construction companies with crews mobilized to complete construction, with contracts through the first quarter of 2019, and the Request for Proposal process for the 2019 projects that are not currently contracted is ongoing and on track to be in place in time to meet the project schedule. 5 TR 1971. The Company is prepared to undertake the work.

Staff also expressed concern that the 30 new control houses (of 50 identified) did not align the projects in Exhibit A-24 (JRA-9). 6 TR 2396. However, there is an explanation for the misalignment. Mr. Anderson testified:

“As seen in Exhibit A-124 (JRA-19), 20134-ST-CE-357 (supplemental), there are six common projects identified when the 30 ‘New CCH’ projects in discovery response 20134-ST-CE-357 Attachment C is compared to the projects on Exhibit A-24 (JRA-9), pages 4, 5, and 6. Moreover, the reason that not all 30 ‘New CCH’ projects are found in Exhibit A-24 (JRA-9) is due to the project timing. The scope of the Substation Communication Upgrades sub-program is to replace the existing analog multi-drop circuits at 230 substations, 131 of which are planned for the 2019 test year, as Mr. Becker acknowledges on page 21, lines 5 and 6 of his direct testimony. Since the analysis of the 230 substations included 2018 and 2019 projections and resulted in 30 new control house projects, it is reasonable that only a subset of these 30 new control house projects appear on the list of 131 substation locations planned for 2019, as listed in Exhibit A-24(JRA-9), pages 4, 5, and 6. The remaining projects were undertaken in 2018.” 5 TR 1971-1972.

Additionally, Exhibit A-124 (JRA-19) contains the voltage to ground and clear distance measurement condition(s) not met relative to the National Electrical Safety Code (“NESC”) working space Table 125-1, establishing the need for a new control house at these

six substations. Exhibit A-125 (JRA-20) provides NESC Table 125-1, which was provided to Staff in discovery.

Staff witness Becker alleges that there is further misalignment between the projects as one of the projects also shows up in Exhibit A-24 (JRA-9) and is also being accounted for in the North American Energy Reliability Corporation (“NERC”)/NESC Compliance sub-program within the Electric Operations Other Program. 6 TR 2397. This is inaccurate. It appears that the project referenced by Staff is the Wexford substation. While the Wexford project appears in two lists, these lists were developed for two different purposes. 5 TR 1973. However, the capital expenditures for the Wexford project are included, or accounted for, only once in the Company’s proposed capital spending, which is on Exhibit A-24 (JRA-9), page 7, line 37.

The Company has projected a reasonable spending amount related to the Substations Communications Upgrades sub-program. The work in this sub-program is all accounted for and is underway. This sub-program provides benefits to customers and is critical to ensure real-time SCADA communication with these substations continues as analog telecommunications circuits until these substations are abandoned by the telecommunications carriers in the near future. Maintaining SCADA functionality, which provides remote control and monitoring capabilities at substations, is essential for maintaining safe and reliable operation of the distribution system. Thus, the projected expenditures for the Substation Communication Upgrades are reasonable, prudent, and well-supported by the Company. These expenditures address telecommunications upgrades that are aging, becoming obsolete, and will soon no longer be supported by telecommunications carriers and will allow the Company to maintain situational awareness while improving cybersecurity with more modern equipment.

(v.) **HVD Electric Operations Other**

The HVD Electric Operations Other Program expenditures are for Computer and Equipment, System Control Projects, NERC requirements/NESC working space requirements, and Substation Fall Protection. The Company is projecting Electric Operations Other capital expenditures of \$5,030,000 in 2018 and \$5,638,000 in the projected test year 2019. Exhibit A-12 (JRA-1), Schedule B-5.4, page 2, line 6, columns (c) and (f). Staff proposed that these amounts be adjusted by \$5,844,000 for the 2018 projected bridge year and \$5,466,000 in the 2019 projected test year. 6 TR 2405.

The NERC/NESC Compliance sub-program consists of the capital expenditures necessary to address working space issues that exist in some of the Company's substation control houses. The NESC, as adopted by the MPSC, serves as a basis for Consumers Energy's engineering standards, and modifications to address these standards are typically made in conjunction with projects associated with other capital sub-programs such as HVD System Protection and HVD Lines and Substations Capacity. 5 TR 1922. This allows for an efficient and effective use of design and construction resources by accomplishing two objectives within one project. *Id.* The Company is projecting NERC/NESC Compliance capital expenditures of \$2,920,000 in 2018 and \$3,160,000 in the 2019 projected test year. Exhibit A-23 (JRA-8), line 3, columns (c) and (f). Basing the Company's future requirements on historical spending is not reasonable for two reasons. First, the Company needs to invest in capital projects that facilitate improved real-time system operations and increase the operational visibility of its control centers. 5 TR 1979. Second, due to the manner in which the NERC/NESC Compliance sub-program is accounted for, the work undertaken would not be reflected in the HVD Electric Operations Other expenditures.

The funding under the NERC/NESC Compliance sub-program is unique. Contrary to Staff's assertion (6 TR 2405), the spending of this sub-program is not unique due to the fact that it is distributed through the year. The manner in which the funds are actually accounted is unique. In reviewing the 2017 expenditures, it appears that the actual capital expenditures incurred for the NERC/NESC Compliance sub-program is \$0. This is incorrect. Actual capital expenditures incurred are not tracked to the sub-program like all other sub-programs. 5 TR 1923. The funds used to address working space are initially established in the NERC/NESC Compliance sub-program and then transferred to other sub-programs when working space projects are identified. 5 TR 1923. This process allows the Company to perform working space modification work in conjunction with other projects, such as relay replacements in the HVD System Protection sub-program and substation additions typically found in the HVD Lines and Substation Capacity sub-program. 5 TR 1924. The table below shows that there was a total of \$2,550,000 transferred from the NERC/NESC Compliance sub-program.

Control House Budget Transfers from NERC/NESC Compliance			
Date of Transfer	Amount	From Sub-Program	To Sub-Program
April 2017	\$225,000	NERC/NESC Compliance	HVD Subs Reliability
April 2017	\$1,650,000	NERC/NESC Compliance	System Protection
April 2017	\$675,000	NERC/NESC Compliance	HVD Lines & Subs Capacity
Total	\$2,550,000		

Exhibit A-24 (JRA-9) provides the projects to be undertaken as part of the NERC/NESC Compliance sub-program. Exhibit A-24 (JRA-9), page 7, lines 36 through 38, lists three projects below the HVD Lines and Substations Capacity total, and these three projects are NESC working space projects. There is an additional NESC working space project shown on Exhibit A-24

(JRA-9), page 3, line 50, below the HVD System Protection sub-program. In reviewing the projects, Staff contends that one of the projects is accounted for twice. 6 TR 2405. This is inaccurate. Company witness Anderson explained:

“The project in question is at Wexford substation which is listed on line 29 of 20134-ST-CE-357 Attachment C (Exhibit S-14.4 (TJB-5), page 7), and in Exhibit A-24 (JRA-9), page 7, line 37, as stated by Mr. Becker. The purpose of 20134-ST-CE-357 Attachment C was to demonstrate the methodology used to determine the solution of either a ‘Weather Proof Cabinet’ or a ‘New CCH’ to be used at the 50 substations within the scope of the Substation Communications upgrade project that have NESC working space concerns. This is further explained in my direct testimony on page 50, line 22, through page 51, line 7. Attachment C does not include projected project costs or capital expenditure requests. Exhibit A-24 (JRA-9) is a list of projects within various sub-programs and includes the projected capital project costs for the test year, which represents the Company’s capital expenditure request. In other words, Exhibit A-24 (JRA-9), page 7, line 37, represents the Company’s request to recover its capital expenditures at the Wexford substation; discovery response 20134-ST-CE-357 Attachment C simply provides more information about the Company’s decision-making in choosing to determine the best course of action at the Wexford substation, in response to Staff’s discovery request. Therefore, the fact that the Wexford substation project appears on both lists does not mean that the Company has included the projected capital amount for the project of \$715,000 twice in its capital expenditure request.” 5 TR 1977-1978.

Staff further questions the Company’s NERC/NESC Compliance spending alleging that the Company was unable to support its NESC work through voltages and measurements. 6 TR 2405. However, Staff never requested this information. While it appears that Staff is referencing discovery response 20134-ST-CE-357 as support for this assertion, this interrogatory only requested information on projects in the Substations Communication Upgrades sub-program, not the Electric Operations Other capital Program, nor these four NESC working space projects funded from this sub-program. 5 TR 1978. This information is available, and the Company later provided it to Staff. 5 TR 1979.

The expenditures for the HVD Electric Operations Other Program are reasonable and prudent. Staff's proposed adjustment fails to take into consideration how the projects for the Company's NERC/NESC Compliance sub-program are accounted for, and by utilizing a historic expenditure amount, fails to account for the expenditures actually incurred. Therefore, the Company requests that its projected amounts for the HVD Electric Operations Other Program be adopted.

(vi.) **LVD Lines New Business**

The Company's LVD Lines New Business investments include the cost of serving new commercial, industrial, residential, and municipal lighting customers. 4 TR 1143. 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. 4 TR 1143. Projects within the LVD Lines New Business Program are initiated by customers, whom the Company must serve so long as the requesting party meets the tariff requirements. 4 TR 1143. In general, the Company does not have advanced knowledge of these types of New Business projects as they are often served within the same year of request. 4 TR 1143.

At 6 TR 2384, Staff witness Becker recommends that the Company's 2019 LVD Lines New Business spending be held to a three-year average of actual spend, years 2015 through 2017, adjusted for the 5% forecasted growth each year after 2017. This recommendation results in a \$4.3 million reduction to the Company's proposed 2019 spending. Mr. Becker's recommendation should be rejected because his calculation of 2019 LVD Lines New Business spending is flawed, unsupported, and unreasonable.

As an initial matter, and as discussed above, Mr. Becker's calculation of 2019 LVD Lines New Business spending is flawed. The inflation factor used by Mr. Becker to calculate his

proposed 2019 spending amount is not based on any particular source and Mr. Becker has provided no support in the record as to how it was calculated or why his inflationary factor is reasonable. 4 TR 1277. Due to this flaw, Mr. Becker's calculation of 2019 LVD Lines New Business spending should be rejected.

The Company also disagrees with Mr. Becker's general approach of using a three-year average to project 2019 LVD Lines New Business spending. Mr. Bordine explained that Mr. Becker's approach is overly simplistic and unsubstantiated. 4 TR 1282. Similar to Mr. Becker's use of the inflation factor discussed above, Mr. Becker provides no justification for using a three-year average or why such an approach is appropriate means for projecting LVD Lines New Business spending. 4 TR 1282. A three-year average also over simplifies actual year-over-year growth rates and the 2018 projected year-end LVD Lines New Business costs. 4 TR 1282.

Furthermore, Mr. Becker's use of a three-year average only considers total spending levels and fails to consider changes in other underlying drivers and economic indicators that the Company monitors for prudent investment planning. 4 TR 1282. This is a critical flaw in Mr. Becker's calculation because the Company's investments in New Business typically rise and fall in correlation with Michigan's overall economic health. 4 TR 1282-1283 Mr. Becker's approach also ignores other factors that the Company has used to more accurately plan for 2019 such as efficiency gains and observed changes in Michigan housing volumes. 4 TR 1283. By way of example, Mr. Bordine explained that the Company expects to see a continued higher level of distribution underground projects due to housing shortages in the state. 4 TR 1283. Mr. Becker's failure to address factors which drive New Business results in an unreasonable projection of LVD Lines New Business spending.

In addition to the above, Mr. Becker's proposed 2019 LVD Line New Business spending fails to consider that customer service requests are required to be met by the Company. 4 TR 1283. This is important to consider because the Company would still need to complete customer service projects even if the Commission were to approve an LVD Lines New Business spending amount which is insufficient, as Mr. Becker has proposed. 4 TR 1283. In such a scenario, the Company would be forced to divert capital resources from other areas of the business, particularly LVD Lines Reliability. 4 TR 1283. It should also be noted that the Company's average historical level of spending is already lower than what is required by the Company in the 2018 bridge year and 2019 test year. 5 TR 1283. Therefore, Mr. Becker's proposal, which provides for insufficient recovery of New Business costs, will unreasonably cause a decrease in LVD Lines Reliability investments, as capital resources are diverted to cover required New Business projects.

For the reasons discussed above, Mr. Becker's LVD Lines New Business recommendation should be rejected. Unlike Mr. Becker's proposed 2019 LVD Lines New Business amount, the Company's proposal for this cost category is extensively supported in this record. The Company's 2019 New Business forecast for growth is consistent with the growth projected by the National Association of Home Builders. 4 TR 1284. Furthermore, the Company's proposed spending amount takes into account the year-over-year growth rates and 2018 projected year-end costs need to be taken into account for these programs. 4 TR 1284. In addition, the Company's proposed spending amount takes into account that customer service requests for New Business service are required to be met. 4 TR 1284. Properly funding New Business, as proposed by the Company, will help to maintain proposed LVD Lines Reliability spending and will avoid capital investments being diverted from this category to support

underfunded New Business projects. The Company's proposed 2019 spending amount is reasonable and should be approved.

(vii.) LVD Lines Reliability

The Company's LVD Reliability investments ensure long-term safe and reliable operation of the LVD system, by making investments to install, upgrade, and rehabilitate LVD lines. These investments also support reductions in customer outage frequencies and duration. See 4 TR 1155-1170. Mr. Becker recommends that the Company's LVD Lines Reliability projected spending plan for 2018 and 2019 be held to the five-year average actual spend levels (2013-2017), adjusted for inflation. 6 TR 2391. However, similar to Mr. Becker's recommendation with respect to LVD Lines New Business, Mr. Becker fails to support the inflationary factor used in his calculation and also fails to establish how a five-year average appropriately projects LVD Lines Reliability spending. Beyond those flaws, Mr. Becker also failed to appropriately consider the underlying details supporting the Company's proposed LVD Lines Reliability spending presented in this case. For these reasons, and the reasons discussed in more detail below, Mr. Becker's recommendation should be rejected.

Mr. Becker's LVD Lines Reliability concerns relate to three main issues: (i) poles replaced due to inspection; (ii) pole replacement versus pole remediation; and (iii) prioritization of targeted circuit improvements. Each of these concerns are addressed below.

(a.) Poles Replaced Due To Inspection

With respect to the Company's poles inspection program, Mr. Becker claims that the Company's management of pole inspections, particularly the replacement of poles during these inspections, sacrifices system reliability and public safety. Mr. Becker also alleges that "the increase in demand failure numbers could be a sign that the Company is not efficiently identifying deteriorated or failing poles during O&M activities and is replacing them during

storm or other demand failures as a reactive process which results in lower system reliability, higher costs, and decreased safety.” 6 TR 2388-2389. Mr. Becker’s above assertions are incorrect and unsupported in the record.

Mr. Becker provides no support for implying the Company’s planned spending level for the pole inspection program is imprudent. Mr. Becker also does not identify what he believes to be a more reasonable amount of investment for this category. 4 TR 1286-1287. Mr. Becker’s allegation regarding the cause for the increase in demand failures spending is also speculative. Mr. Becker indicates that the Company’s pole inspection program “could be a sign” that it “is not efficiently identifying deteriorated or failing poles during O&M activities” but Mr. Becker provides no evidence to support this assertion. Mr. Bordine addressed Mr. Becker’s pole inspection criticisms and explained that, contrary to Mr. Becker’s suggestion, “the level of demand failures is a result of a number of factors including asset age, line clearing cycles, storm events, and so on.” 4 TR 1287.

Furthermore, Mr. Becker’s assertion that the Company’s management of its LVD pole inspection program “sacrifices system reliability and public safety” is contradicted by his recommendation to reduce LVD Lines Reliability spending by \$8,391,000. See Exhibit S-14.1 (TJB-2). Poles identified during inspection are replaced out of the LVD Lines Reliability. 4 TR 1287. While Mr. Becker appears to suggest that the Company should impact more of its system with pole inspection spending, reducing money from this cost category would cause a reduction in the amount of poles which the Company can replace in a given year. 4 TR 1287. Mr. Becker’s proposal therefore fails to provide the Company with the ability to replace poles prior to failure.

It is also not true that there has been an increase in LVD poles replaced as a result of demand failures, as Mr. Becker suggests. To form this conclusion, Mr. Becker appears to be relying on outdated information. This was explained by Mr. Bordine as follows:

“On page 14 of his direct testimony, lines 11 through 14, Mr. Becker points to a perceived increasing trend in poles replaced due to storms and other demand failures. Mr. Becker refers to 2,092 poles replaced for High Voltage Distribution (‘HVD’) and LVD in 2015. However, starting in 2016, there was a correction to the reporting to better reflect the number of poles replaced in LVD and HVD in Demand Failure. The way the Company was pulling the data previously from the Company’s SAP system was inadvertently omitting other poles. This was explained to Staff during the reliability review in April of 2016. The revised number of poles replaced in 2015 is 5,893 for LVD only. Due to the change in reporting, the 2015 and prior Pole Inspection Report references to poles replaced in the Demand Failure program should not be considered.” 4 TR 1288.

Therefore, based on the updated information in the Pole Inspection Report, there has not been an increase in poles replaced due to storms and other demand failures.

Mr. Bordine further explained that there is no evidence to establish that poles that were replaced under the LVD Demand Failures Program were rejected in the pole inspection program. 4 TR 1288. Poles replaced after storm events have unrelated failure modes, such as high winds, independent of the Company’s inspection program. 4 TR 1288. Therefore, the number of poles replaced under LVD Demand Failures can only be correlated to storm activity that occurs in the year and not necessarily related to the rate of replacement due to inspection, as Mr. Becker suggests.

The same reasoning as provided above applies to Mr. Becker’s suggestion that the Company needs to reduce its backlog of rejected poles to have fewer poles replaced under the LVD Demand Failure Program. 6 TR 2403. Demand failures are weather dependent. Therefore, reducing the inspection of rejected poles backlog will not, in and of itself, reduce

poles replaced through the LVD Demand Failures Program. 4 TR 1289. Mr. Becker also fails to recognize that there are thousands of poles replaced in other planned work which occurs within the LVD Reliability, LVD Repetitive Outage, LVD Capacity, and Electric LVD Relocation Programs. 4 TR 1289. Thus, since poles are replaced in programs other than pole inspections, it is not reasonable to assume that reducing the backlog of rejected poles results in a reduction to poles replaced under LVD Demand Failures.

(b.) Pole Replacement Versus Pole Remediation

Mr. Becker's next concern regarding the Company's LVD Lines Reliability Program relates to pole remediation. Mr. Becker recommends that the Company begin utilizing pole remediation and suggests that utilizing pole remediation in addition to pole replacement would decrease reactive capital spending on poles and improve customer safety and reliability. 6 TR 2390. This recommendation should be rejected because Mr. Becker has failed to support the reasonableness of pole remediation and the alleged corresponding decrease to reactive capital spending and increase in safety and reliability. Mr. Becker's recommendation was also completely refuted in the record by the Company.

Mr. Becker suggests that the Company has not repaired poles in accordance with accepted engineering principles because the Company replaces, instead of remediates, all poles that fail the LVD pole inspection. 6 TR 2389. However, this suggestion is not supported in the record. First, when asked in discovery, Mr. Becker could not demonstrate that the Company has violated any accepted engineering principles with its pole inspection and replacement practices. 4 TR 1290-1291; see also Exhibit A-136 (AJB-20). Second, while Mr. Becker did reference the NESC as a source of accepted engineering principles, he stated that "[t]he 'accepted engineering practices' as referenced in the context would either be remediation (repair) or replacement of

poles that have failed the pole inspection as accepted by the National Electric Safety Code (“NESC”).” See Exhibit A-136 (AJB-20). Therefore, even though Mr. Becker criticizes the Company’s use of replacement to address failed poles, he also concedes that pole replacements are an accepted engineering practice. 4 TR 1291.

In a different discovery response provided by Mr. Becker, provided as Exhibit A-137 (AJB-21), he attempts to support his recommendation by pointing to a National Association of Regulatory Utility Commissioners (“NARUC”) Winter Policy Summit presentation, provided as Exhibit A-138 (AJB-22). Upon inspection of this presentation, it was revealed that the presentation does not support Mr. Becker’s pole remediation recommendation. The NARUC presentation shows that the expected service life of an un-remediated wood pole is 40 years. 4 TR 1291. Mr. Bordine explained that since the majority of the Company’s HVD and LVD poles are 40 years old or older, a large portion of the poles that Mr. Becker proposes to remediate would already be past their useful life. 4 TR 1291. This would negate the benefit of remediation. Furthermore, it should be noted that the NARUC presentation does not give a blanket endorsement of pole remediation and instead concedes that “[t]he effectiveness of pole maintenance programs varies greatly.” See Exhibit A-138 (AJB-22), page 19.

In the discovery responses referenced above, Mr. Becker also points to the NESC, the DTE Electric Distributions Operations Five-Year Investment and Maintenance Plan (“DTE Distribution Plan”), and the Osmose website as support for pole remediation. See Exhibit A-137 (AJB-21). However, none of these sources provide sufficient support for Mr. Becker’s position. The NESC does not provide an inspection or remediation process. 4 TR 1292. The DTE Distribution Plan indicates that poles are either replaced **or** reinforced and makes no distinction between how many poles are replaced versus how many are reinforced. 4 TR 1292. Finally,

Osmose is a company that provides remediation services and is therefore not an unbiased source. 4 TR 1293. The website linked by Mr. Becker only serves to demonstrate that remediation services are available for purchase by interested parties at a cost.

Mr. Becker's assumption, that pole remediation will instantaneously reduce reactive capital spending and improve safety and reliability, is also flawed. 4 TR 1290. Remediation does not result in the instantaneous improvement of poles replaced during events like storms or other demand failure events. 4 TR 1290. This is because there is a lag between when the remediation occurs and when any purported benefits are observed. 4 TR 1290. Mr. Bordine explained that in order to achieve lower failure rates during storms and other demand failures, the replacement or remediation rates would have to be higher than pole degradation rates. 4 TR 1290. Therefore, poles need to be addressed within LVD Lines Reliability at a higher rate than they have been addressed historically, and over a longer period of time, to overcome the deterioration rate. This is notable because, as explained above, Mr. Becker is recommending an \$8,391,000 reduction to LVD Lines Reliability and poles identified during inspection are replaced out of this category. Mr. Bordine explained that the LVD Lines Reliability amount proposed by Mr. Becker prevents the Company from impacting more of the LVD system because it does not allow the Company to address poles at a higher rate than the degradation rate. 4 TR 1293.

(c) Prioritization Of Targeted Circuit Improvements

Mr. Becker's final LVD Lines Reliability concern relates to prioritization of targeted circuit improvements. 6 TR 2390. Mr. Becker suggests that "Staff is also concerned with the fact that targeted circuit improvements are largely prioritized considering tree outages." 6 TR 2390. Mr. Becker further suggests that effective implementation of the tree trimming program "would significantly minimize the need to perform work on the circuits identified for targeted

first zone work.” 6 TR 2391. This concern should be rejected because it fails to properly represent how all targeted work is selected by the Company for reliability improvements. 4 TR 1293.

Mr. Bordine explained that all outage types that occur on the LVD system are considered to be contributors to the zone’s performance. 4 TR 1293. The outage types that the Company considers include, but are not limited to, tree, equipment, animal, and third-party damage outages. 4 TR 1293-1294. Mr. Bordine also generally described the Company’s circuit improvement assessment process as follows:

“As described on page 42, lines 11 through 13, of my direct testimony, the Company will perform a driving assessment of the zone being targeted for circuit improvement to identify the correct improvement method to reduce interruptions. The Company uses interruption history to review all outage types on the LVD system as background information prior to the driving assessment. If the solution requires tree clearing, the Forestry team will clear accordingly as described on page 42, lines 11 through 13 of my direct testimony.” 4 TR 1294.

Thus, the Company considers numerous outage types when targeting circuit improvements, not just tree outages as Mr. Becker suggests. Furthermore, since there are numerous outage types that are improved through targeted circuit improvements, Mr. Becker’s assumption that the “tree trimming program” would reduce the need to improve targeted areas is false since it neglects all outage types and regrowth outage reduction. 4 TR 1294.

(viii.) Demand Failures

The Company’s Demand Failures Program includes the following categories: (i) LVD Lines Demand Failures; (ii) Distribution Metering; (iii) Distribution Transformers; (iv) Streetlight – Mercury Vapor (“MV”); and (v) Metro Demand Failures. 4 TR 1208. These investments provide both immediate customer benefits through service restoration and

longer-term customer benefits due to having new equipment providing service. See 4 TR 1208-1232; Exhibit A-43 (AJB-10), page 2.

At 6 TR 2404, Mr. Becker recommends that projected 2019 spending in the Demand Failures Program be adjusted to \$132,218,000 based on the five-year actual average (2013-2017) across the entire program and adding \$5,000,000 adjusted for Staff's inflation as shown in Exhibit S-14.2 (TJB-3), line 1, column (g). As discussed above, this recommendation should be rejected because Mr. Becker has failed to support the reasonableness of using a five-year average to project these costs and also fails to support his inflationary adjustment. Furthermore, Mr. Becker's criticisms regarding Demand failures should also be rejected because they have not been substantiated in the record.

The primary issue with Mr. Becker's criticism of Demand Failures is that he only focuses on capital expenditures for poles replaced during storms and other demand failures. 4 TR 1294. However, the Demand Failures Program includes multiple expenditures within service restoration activities, street light failures, emergent rehabilitation, other rehabilitation, voltage improvement, system protection, and security assessment repairs. 4 TR 1295. In other words, Mr. Becker is proposing to reduce all projected Demand Failures expenditures on account of only one component of Demand Failures, pole replacements. Mr. Becker also does not attempt to quantify the amount of pole replacements spending which makes up total Demand Failures spending. It is inappropriate and unreasonable for Mr. Becker to recommend a reduction for the entire Demand Failure Program when he only addresses one component of Demand Failures, pole replacements.

Mr. Becker's proposed Demand Failures spending amounts are also contradicted by his own recommendations. Mr. Becker asserts that it is best to project future spending with

historical spending amounts but then proposes a 2019 spending amount which is lower than the amount he adopted for 2018. 4 TR 1296. Specifically, Mr. Becker adopted the Company's 2018 LVD Demand Failures Program spending amount of \$145,460,000 but then reduced the 2019 amount to \$132,218,000 plus an inflationary adjustment. See Exhibit S-14.2 (TJB-3). Mr. Becker's attempt to reduce 2019 Demand Failures spending below the 2018 amount undermines his position that historical spending should set future spending amounts.

Mr. Becker's Demand Failures recommendation is particularly unreasonable given his proposed \$8,391,000 reduction to the Company's 2019 Lines Reliability spending amount, as addressed above. Mr. Bordine explained that there is an upward trend in Lines Demand Failures spending and that asset deterioration is the leading cause of this trend. 4 TR 1296-1297. Increased proactive spending in reliability programs, as proposed by the Company, would be required over five or more years to have a decrease in spend in the Demand Failures Program. 4 TR 1297. Mr. Becker's proposal will lead to equipment out of service and deteriorated distribution lines and equipment not being replaced causing higher frequency of interruptions. 4 TR 1297. Mr. Becker's proposed Demand Failures spending levels should therefore be rejected by the Commission because they are unreasonably low.

(ix.) Grid Capabilities

The Company's Grid Capabilities – Automation sub-program includes investments in grid devices and coordinated infrastructure upgrades to improve grid management for better grid resiliency and reliability, enabling implementation of substation, and line automation on the system. 4 TR 1180. This includes both upgrades to aging infrastructure and installation of new distribution system devices and controls. These investments will develop a capability known as Fault Location, Isolation, and Service Restoration (“FLISR”) to improve reliability. 4 TR 1181. These investments will also develop a Volt-Var Optimization capability to improve

sustainability. 4 TR 1181. The Grid Capabilities – Automation sub-program includes the following categories: (i) Distribution Supervisory Control and Data Acquisition (“DSCADA”); (ii) SCADA; (iii) Automatic Transfer Reclosers (“ATR”); (iv) Line Sensors; and (v) Regulator Controllers. See 4 TR 1182-1192.

The Company Grid Capabilities – Advanced Technology sub-program investments will implement several software components, data readiness, and emerging operational demonstrations to provide for a more modern and adaptable distribution system. 4 TR 1192-1193. This includes advanced distribution management applications allowing for more system visibility, system control, and integration of Distributed Energy Resources (“DER”). 4 TR 1192. The categories in this sub-program include: (i) Advance Distribution Management System (“ADMS”); (ii) Electric System Model Enhancement (“ESME”); and (iii) Grid Operational Analytics. 4 TR 1194-1200.

At 6 TR 2401, Mr. Becker recommends that the Grid Capabilities: Automation sub-program be adjusted to 2017 actual spend plus 50% in 2018, adjusted for Staff’s inflation. Furthermore, at 6 TR 2401, Mr. Becker recommends the Grid Capabilities: Advanced Technology sub-program be adjusted to 2018 projected bridge year spend, adjusted for Staff’s inflation. Similar to the other programs addressed in the prior sections of this Initial Brief, Staff’s adjustments to these Grid Capabilities sub-programs should be rejected because Mr. Becker has failed to support the use of historical amounts to project future spending and also has failed to support his inflationary adjustments. Furthermore, Mr. Becker’s rationale for reducing cost recovery in these programs is flawed.

Mr. Becker’s concern with the Company’s ability to spend projected amounts for the Grid Capabilities Automation and Advanced Technology sub-programs is unsupported.

Mr. Bordine explained that construction contracts are currently in place for all major projects through at least the end of 2018 and early 2019 and additional construction contracts are in process for all remaining work in 2019. 4 TR 1297. Mr. Bordine also provided extensive examples of Grid Capabilities contracting activities as follows:

“For example, Electric System Model Enhancement (‘ESME’) has a contract in place through 2019 and Automatic Transfer Reclosers (‘ATR’) automation loops has construction contracts through Q1 2019 and is on track to have remaining 2019 construction contracted by year end. ESME is a project to improve our electric system model data with accurate three-phase electrical connectivity of the distribution system as well as accurate physical and load characteristics, which are required for modern grid applications. Our electric distribution system model is stored in our Geographical Information System. ATR is a technology installed as sets on our distribution system creating an automation loop. ATRs transfer load automatically in the event of an outage, reducing customer outages, and improving system reliability by isolating a faulted section of a distribution circuit. In 2017, the Company developed over three thousand detailed Advanced Distribution Management System (‘ADMS’) requirements. In 2018, the Company focused on procurement activities for an ADMS solution and system integration strategy. The Company has completed Request for Proposal (‘RFP’) development and submittal, bid evaluations, bid presentations, and demonstrations from both the ADMS product vendors and System Integrators. The Company has selected an ADMS product vendor and has short listed the System Integrator vendors. The Company is on track to complete contract negotiations with both the product vendor and System Integrator by year-end 2018. ADMS is the integration of four key software application components that include Supervisory Control and Data Acquisition (‘SCADA’), Distribution Management System (‘DMS’), Outage Management System (‘OMS’), and Distributed Energy Resource Management System on a single platform.” 4 TR 1297-1298.

Based on this substantial progress established by Mr. Bordine, the Company is able and prepared to spend the projected expenditures in Grid Capabilities of Automation and Advanced Technology, contrary to Staff’s claim.

At 6 TR 2400, Mr. Becker further asserts that Staff has not been assured that all three overarching categories of Grid Capabilities, telecommunications, grid devices, and advanced application, “will communicate together on the same platform and be optimized in a way that will provide the utmost benefit to customers.” This is incorrect. The Company has established that its Grid Capabilities deployments use a multi-year, layered deployment plan to improve reliability, sustainability, and customer control. See, e.g., 4 TR 1181, 4 TR 1298. Mr. Bordine also explained that the Company’s EDIIP report focuses on the overall logic of the Company’s grid modernization plan and how the different technologies and investments fit together over a multi-year roadmap. See Exhibit A-111 (TJS-1), pages 58-60. Furthermore, the Grid Capabilities Automation and Advanced Technology in the Company’s EDIIP roadmap are aligned with the US Department of Energy’s “MODERN DISTRIBUTION GRID Decision Guide Volume III” document, page 26, “Next Generation Distribution System Platform & Applications.” 4 TR 1299. Mr. Bordine also explained that the Company’s Conservation Voltage Reduction (“CVR”) Program is an example of the optimization of Grid Capabilities components. 4 TR 1299.

Mr. Becker further asserts that the significant spending increases proposed by the Company warrant some sort of cost-benefit analysis. 6 TR 2400. The Company does not disagree with this assessment and, contrary to Mr. Becker’s inference, has developed cost-benefit models for components of the Grid Capabilities Automation and Advanced Technology sub-programs and continues to enhance each model as deployments mature with new capabilities. 4 TR 1300. These models and the Company’s careful approach to deploying Grid Capabilities components were extensively addressed by Mr. Bordine as follows:

“The Company carefully considers the benefit of particular sites when choosing which areas to deploy advanced communicating

devices. The DSCADA program first chooses sites which support feeders with ATR loops to increase visibility into these key areas. Then, additional sites are selected based the worst Customer Average Interruption Duration Index impact, which represent the most effective substations to upgrade first.

“The ATR planning process is sequenced; starting with all potential circuit ties statewide, and applies multiple filtering criteria to narrow down the most likely collection of potential loops. These concepts are then evaluated by local engineers to establish viability and scope. Then concepts are ranked by cost/benefit ratio, where those with the highest score are selected for immediate deployment each budget year. The ATR concepts consider many inputs to provide a unit cost for comparison among potential sites. To account for the cost the following inputs are considered: the number of devices being installed, any line conditioning improvements such as regulator installation or line re-conductoring, and bulk capacity upgrade requirements such as HVD and substation improvements. And to account for the benefit the following inputs are considered: three years outage history for certain outage types which would have specifically affected the customers identified to be automatically transferred.” 4 TR 1300-1301.

Mr. Bordine also explained that Section VII of the Company EDIIP report outlines the planned benefits of Grid Capabilities investments based on cost-benefit analyses. 4 TR 1301; See Exhibit A-111 (TJS-1). These benefits are tracked annually and will continue to be developed as new Automation and Advanced Technology components are implemented. 4 TR 1301. Mr. Bordine further explained that a cost-benefit model is under development for ADMS and will track the incremental benefits that do not include existing benefits from Grid Capabilities Automation or CVR. 4 TR 1301. The CVR Program expenditures proposed in the Company’s ongoing Integrated Resource Plan (“IRP”) filing, Case No. U-20165, are supported by a cost-benefit model, provided in Exhibit A-70 (MAO-4) in that proceeding. 4 TR 1301.

Mr. Becker’s next suggestion, that there are pending pilots and contracts that could significantly impact the spending levels in 2018 and 2019, is incorrect. 6 TR 2400. As explained above, the Company has contracts in place to support the deployment of its annual

capital investments for Grid Capabilities Automation and Advanced Technology. 4 TR 1301. Mr. Bordine further explained that the Company is meeting the current capital spending and deployment plan for 2018 and finalizing additional contracts to support 2019 work. 4 TR 1301. There is no basis to establish that the 2018 and 2019 spending levels could significantly change.

For the reasons discussed above, Mr. Becker's proposed cost reductions and criticisms related to Grid Capabilities Automation and Advanced Technology should be rejected. The record evidence provided by the Company in this case fully explains the expenditures in Grid Capabilities Automation and Advanced Technology and the benefits provided to customers from these investments. These investments are reasonable and prudent and improve customer reliability, system optimization, and reduce O&M expense. The Company has also established that it has contracts in place to deploy these technologies consistent with the Company's 2018 and 2019 capital expenditures presented in this case. The Commission should therefore approve the Company proposed 2018 and 2019 spending for Grid Capabilities Automation and Advanced Technology.

c. Areas Of Dispute With The Attorney General

Prior to reviewing the Company's proposed electric distribution expenditures, Attorney General witness Sebastian Coppola testified regarding the Company's SAIDI reduction target of 120 minutes and how this relates to the Company's EDIIP. 6 TR 2778-2779. In his testimony, Mr. Coppola reasons that:

“It is also noteworthy to point out that the capital expenditures for Demand Failures remain relatively flat over the five-year period. On the other hand, Reliability expenditures increase from \$111 million in 2017 to a high of \$232 million during the projected 2018-2022 period. On average over the five-year period, the Company is spending close to \$200 million annually on system reliability projects. This is nearly a 100% increase in capital expenditures from the level in 2017. However, this increase in capital expenditures does not match the decline in SAIDI.

Achieving a SAIDI of 120 minutes in 2022 represents a cumulative decline of approximately 25% from the 160.9 minutes reported in 2017.

“The increase in capital expenditures in key areas of the EDIIP does not match the forecasted decline in service outages.” 6 TR 2779.

This reasoning is flawed. Through the discovery process, the Company attempted to discover the reasoning underlying Mr. Coppola’s assertions about the relationship between capital investments and SAIDI. In his discovery response, Mr. Coppola acknowledged he has no modeling to substantiate his comments and his assertions are guided only by what “seems reasonable” to him. See Exhibit A-127 (JRA-22). On the other hand, the Company has developed models, like the Grid MD model, to estimate the projected SAIDI impact by the year 2022. The Company reasonably relies on its modeling to provide a reasonable basis for the SAIDI targets that the Company is projecting based on its capital investments.

Additionally, in reviewing the Attorney General’s argument, it should be noted that the average 2018 through 2022 reliability capital spending is \$185 million, or approximately a 60% increase from 2017, as opposed to the inflated 100% increase stated in Mr. Coppola’s direct testimony. 5 TR 1985. In making his argument, Mr. Coppola referred to an increased spending in the amount of \$232 million. A breakdown of this figure can be seen in the Company’s EDIIP, Exhibit A-111 (TJS-1), page 100, which shows that this figure includes funding for the Substation Communication Upgrade sub-program. While these investments are of considerable importance, as they are required to address telecommunications upgrades that are aging, becoming obsolete, and will soon no longer be supported by telecommunications carriers, these investments do not translate into direct SAIDI minute savings. 5 TR 1985.

Despite this error, Mr. Coppola’s logic correlating total Demand Failures and Reliability Program capital investments to system-wide SAIDI impacts is oversimplified as these are not

correlated in a perfectly linear manner. 5 TR 1985. Under the Attorney General’s reasoning, a 100% increase in capital expenditures should result in a 100% decline in SAIDI minutes, or a 25% decline in SAIDI should require only a 25% increase in capital expenditures. This is inaccurate. While there is a correlation between increased Demand Failures and Reliability Program capital expenditures and a reduction in SAIDI minutes, the correlation is not linear. Company witness Anderson provides further explanation stating,

“‘The three-year average for HVD overhead line system rebuild and rehabilitation miles were 31 and 58, respectively. A 31 mile per year rebuild represents 0.7% of the overhead HVD system, which is an approximate 140-year rebuild cycle, and a 58 mile per year rehabilitation represents 1.3% of the system.’ Therefore, HVD line rebuilds and rehabilitations addressed an average of approximately 2% of HVD lines per year. Increasing capital expenditures for HVD lines rebuilds and rehabilitations by nearly 100% would allow the Company to address another approximately 2% of HVD line miles per year. This would result in a decline in the SAIDI contribution from HVD lines over five years, but would not reduce that SAIDI contribution by anything close to 100%.’ 5 TR 1986.

In order to make meaningful declines to SAIDI, the Company targets investment locations that provide the greatest reliability benefit first, and subsequent investments would provide a lower marginal benefit. By making these investments, the Company will make meaningful improvements to SAIDI that improve the reliability of the distribution system.

(i.) HVD Lines And Substation Capacity

The Attorney General recommends that the Commission reduce the Company’s HVD Lines and Substations Capacity capital spending by \$13.4 million. 6 TR 2781. This reduction was based on Mr. Coppola’s calculation of a 2017 cost per project for the Company’s capital projects in these sub-programs, and then applying the average cost per project to the Company’s proposed projects shown in Exhibit A-24 (JRA-9), page 7, lines 2 through 34. This methodology is inappropriate.

A review of Exhibit A-24 (JRA-9), page 7, lines 2 through 34, shows that the exhibit already provides specific projected costs for all of the Company's projects. The project projections for this sub-program were reasonably based on engineering estimates. 5 TR 1984. The use of Company specific projections based on the specific projects being undertaken is a more reasonable method to determine project costs than inferring that "total costs" and "number of projects" would track from year-to-year on a one-to-one basis.

Company witness Anderson explained why the 2019 costs increased compared to other years. When looking at Exhibit A-24 (JRA-9), page 7, the exhibit shows projects of varying costs. Line 34 shows a project in this sub-program that costs \$1,000; however, line 2 shows another project in this sub-program that costs \$3,446,000. This demonstrates the inherent cost variability in the sub-program. 5 TR 1984. The 2019 expenditures include construction of a new 138 kV-to-46 kV bulk power substation in Coopersville. 5 TR 1984. This is the Company's first new bulk power substation since 2010, and since this type of large project does not occur on an annual basis, the costs would not be included in a review of the average annual costs per project. Therefore, the Attorney General's proposed reduction should be rejected as the costs shown in Exhibit A-24 (JRA-9), page 7, lines 2 through 34, are based on engineering estimates, which are a more appropriate way to project costs for this sub-program.

(ii.) LVD Substation Reliability

The Attorney General presents a proposed reduction of \$6,991,000 in LVD Substation Reliability capital spending. The basis for this proposed adjustment as related to substation rebuilds, animal mitigation, regulator replacements, reclosers, and other projects was that the spending was undetermined. 6 TR 2782. This proposal should not be adopted.

To start, the proposed reduction ignores the information provided to parties. Exhibit S-14.4 (TJB-5), pages 14 through 15, discovery response 20134-ST-CE-366, shows that as of

August 2, 2018, the Company had identified \$3,182,000 in specific projects for those categories. Additionally, Attorney General witness Coppola erroneously cited Exhibit A-24 (JRA-9), page 2, line 7, as showing \$816,000 in undetermined substation rebuild spending, when the exhibit in fact showed \$810,000 for that line item at the time of filing. 5 TR 1988. Taking this information into consideration, the Attorney General's proposed reduction should have been lowered.

Moreover, as previously discussed above, the Company indicated that it planned to identify additional substations to receive animal mitigation over the course of the year in 2018. This is a reasonable practice as gathering data throughout the year, before finalizing the animal mitigation project list, allows the Company to undertake projects at the highest priority substations. 5 TR 1968-1969. The Company typically identifies many projects for the next year in the summer and fall timeframe of the current year. *Id.* Exhibit A-123 (JRA-18) provides updated information regarding additional animal mitigation and regulator replacement projects. As shown in that document, the Company has identified the additional projects. Therefore, as there is no longer any undetermined animal mitigation or regulator replacement project spending, the Commission should not disallow any of the Company's projected LVD Substation Reliability capital spending.

(iii.) LVD Substations Capacity

The Attorney General recommends that the Commission disallow \$3.7 million in LVD Substation Capacity capital spending. This recommendation was based on Attorney General witness Coppola's assertion that there was uncertainty as to whether the Seven Mile and Paradise substations will actually be built. 6 TR 2783. This proposed adjustment is unreasonable. It is common that some of the Company's projected spending for 2019 still be undetermined at this point in 2018. This is because it takes time for the details for some new business developments to be fully known. 5 TR 1989. The lack of a signed facilities agreements for the Seven Mile and

Paradise substations is not a reasonable basis to conclude that the projects will not happen in 2019, or that they are uncertain. The new Seven Mile Substation is needed to resolve a Pinconning Substation overload due to a new 13 MVA load being proposed by a new customer, which exceeds the capability of the 5.6/7.0 MVA Pinconning Substation transformer. 5 TR 1896. The Paradise Substation is a new substation to resolve a Kingsley Substation overload due to a new 5 MW load being proposed by a new customer, which will exceed the load limit of the 5.6/7.0 MVA Kingsley Substation transformer. 5 TR 1897. These are reasonable and necessary projects, and the projected test year amount provides for the level of investment necessary in LVD substation capacity needed to ensure adequate and reliable capacity and voltage to serve the Company's customers.

(iv.) LVD Metro New Business

Beginning at 6 TR 2783, Mr. Coppola suggests that certain projects in the Company's LVD Metro New Business expenditures for 2018 and 2019 are placeholders and therefore the amount of money related to these projects, \$1,651,000, should be reduced from the Company's total requested amount. Mr. Bordine explained that the \$1,651,000 amount identified by Mr. Coppola is not a placeholder. Rather, it is based on publically disclosed information for projects planned by property developers. 4 TR 1309. Mr. Bordine further explained that this dollar amount also includes anticipated additional requests that are not yet publically disclosed and considers what the Company has experienced historically for growth in each metro region. 4 TR 1309.

In addition, Mr. Bordine explained that a developer's projected start date for a project, as provided at the time of public disclosure, can be fluid based on the ultimate customer's desired timeline. 4 TR 1309. The projects referenced by Mr. Coppola did not have projected start dates at the time of the filing of this case, as customers had not determined their requested connection

date. 4 TR 1309. However, the Company must fairly assume that the developer will continue with its projects on time until communicated otherwise. 4 TR 1309. If the Company does not plan for such projects it will cause the Company to shift money from other programs to fund New Business and would delay planned work in other capital programs. The Company's requested expenditure amount is not based on placeholders but is instead reasonably based on meeting customers' projected connection dates and historical New Business connections. Therefore, the Commission should not disallow these expenditures.

(v.) **LVD Repetitive Outage**

At 6 TR 2784 through 2786, Mr. Coppola recommends reductions for the Company's proposed 2018 and 2019 LVD Repetitive Outage sub-program expenditures. For 2018, Mr. Coppola asserts that the Company has adjusted its spending in 2018 and therefore it now intends to spend \$3.7 million less than originally projected. 6 TR 2785. For 2019, Mr. Coppola attempted to calculate the average cost of the Company's projected projects and recommends a \$2.2 million reduction. For the reasons discussed below, Mr. Coppola's recommendations should be rejected.

With respect to the 2018 LVD Repetitive Outage sub-program expenditures, it should be noted that, although the Company's spending has dipped in the middle of 2018, the Company still has the remainder of the year to meet its targeted spending projection. Mr. Coppola has not established that the Company cannot spend what it originally projected. Furthermore, Mr. Bordine explained that the LVD Repetitive Outage sub-program addresses customer complaints related to frequent outages to improve the customer experience. 4 TR 1310. Reducing costs to this area, as Mr. Coppola proposes, would lead to decreased system performance and increased customer complaints. 4 TR 1310.

With respect to the 2019 LVD Repetitive Outage sub-program expenditures, Mr. Coppola has failed to properly calculate the average project cost in his attempt to project 2019 expenditures. Mr. Bordine explained that the \$40,179 average project cost, utilized by Mr. Coppola, does not account for the wide range of variability of project costs. 4 TR 1310. As described in discovery response 20134-AG-CE-280, as provided in Exhibit A-139 (AJB-23), the project costs can range from between \$1,000 to \$100,000 per project. Mr. Bordine explained that it is not appropriate to divide the cost in the year by the number of projects to create a new average cost. 4 TR 1310. The appropriate average cost per project is \$50,000. 4 TR 1310-1311. This amount is based on the most recent cost averages in 2017 and the cost averages estimated in 2018, at the time of the Company's rate case filing. 4 TR 1311. Therefore, since Mr. Coppola has not appropriately calculated the average cost of LVD Repetitive Outage projects, his recommended cost reduction should be rejected.

(vi.) Grid Capabilities

At 6 TR 2791, Mr. Coppola recommends a \$45.3 million disallowance to historically incurred Grid Capabilities expenditures between 2015 and 2017 and a reduction to projected 2018 and 2019 costs in the amount of \$34.8 million and \$58.1 million, respectively. In an attempt to support these recommendations, Mr. Coppola claims that the Company's discovery responses to the Attorney General were not "compelling," that a robust cost/benefit analysis does not justify the Company's investment, and that the Company's Grid Capabilities investments are premature. 6 TR 2789-2790. Mr. Coppola's recommendations are unsupported and unreasonable. The Commission should reject Mr. Coppola's proposed cost disallowances and reductions.

Mr. Coppola points to the SAIDI reduction benefit provided by the Grid Capabilities Automation and Advanced Technology sub-programs and suggests that reducing SAIDI by

three minutes does not seem to justify Grid Capabilities investments of more than \$273 million. 6 TR 2789. However, in forming this conclusion, Mr. Coppola misunderstands the Company's discovery response to question 20134-AG-CE-281, provided as Exhibit AG-10. The Company's response to 20134-AG-CE-281 was specifically focused on the "last two major storms" and the benefits of advanced grid technologies during those storms. 4 TR 1311. At the time the discovery response was provided, the last two major storms were comparatively mild, making the projection of 2.8 SAIDI minutes from ATR loops less than impressive. 4 TR 1311. Further, that projection did not include any of the remainder of outages restored by way of those devices during a year. 4 TR 1311. Mr. Bordine further explained the benefits of Grid Capabilities components, such as ATR, in reducing SAIDI as follows:

"Starting the week of August 26, 2018, the Company experienced a major storm. At current levels of ATR deployment, this storm alone yielded 1.7 SAIDI minutes avoided. Extrapolating out for a system after having implemented the projected deployment plan through 2022, that same storm would have experienced 9.1 SAIDI minutes avoided from ATR loops only. For additional context, based on this year's year-to-date ATR operation benefits, the extrapolated ATR benefit by 2022 for the entire year SAIDI impact would be 11.8 (not including major storms)." 4 TR 1311-1312.

Therefore, the benefits provided by ATR, a component of the Company's Grid Capabilities Program, are vastly more significant than a three minute reduction in SAIDI and better reflects the impressive benefits which accompany the series of investments being made to the LVD system in the Grid Capabilities Program. 4 TR 1311-1312.

In addition to Mr. Coppola's misunderstanding discussed above, it is also inappropriate to compare the entire Grid Capabilities Automation and Advanced Technology sub-program budget to the three-minute SAIDI reduction cited earlier, because not all devices and initiatives

implemented as part of Grid Capabilities have the core benefit of improving reliability.

Mr. Bordine established additional benefits of these investments as follows:

“Other benefits to the business and customers such as worker and public safety, improved efficiency, reduced wear on equipment, and reduced generation needs are all reaped from the full ADMS and grid automation programs. The largest contributor to reliability is the ATR automation loop program, and its contribution to the \$273 million projected spend is only \$84.6 million (2018-2022). Further, as additional functionality from ADMS Fault Location, Isolation, and Service Restoration (‘FLISR’) becomes available, the ATR automation loop deployment is expected to continually improve on opportunities. ADMS will enable the Company to no longer need to build loop transfer capacity for the worst case customer loading. Instead, real-time power flow and decision-making in the ADMS will enable automated switching in areas previously cost prohibitive, reducing the need for expensive system upgrade investments because the ADMS system will block automatic switching when the infrastructure cannot serve the load after switching during heavy load periods. The result will increase the quantity of schemes that can be deployed for more reliability benefit, all at a lower cost.” 4 TR 1312-1313.

Therefore, since Mr. Coppola has misunderstood the discovery response which led him to his conclusion regarding a reduction in SAIDI and since the Company’s Grid Capabilities investments provide additional benefits beyond a reduction in SAIDI, Mr. Coppola’s criticism should be rejected.

Mr. Coppola’s next criticism suggests that the Company has not presented a “robust cost/benefit” analysis to justify all Grid Capabilities expenditures. Similar to Mr. Coppola’s criticism above, this criticism is equally without merit. Mr. Coppola fails to consider that the Company has completed cost-benefit analyses for the components of Grid Capabilities that it is proposing to implement. 4 TR 1313. A single cost-benefit analysis for the entire Grid Capabilities Program is not available because there is a wide array of devices and systems within the entire program that are each at differing levels of maturity. 4 TR 1313. Mr. Bordine

explained that some components of Grid Capabilities are still in infancy where the full nature of customer benefits is still being explored. 4 TR 1313. Other components have already been deployed for many years, such as ATR loops and DSCADA. 4 TR 1313. The components that have been deployed are supported with robust benefit calculation processes. 4 TR 1313. Once these interdependent technologies are fully deployed, the individual cost-benefit models will be integrated. 4 TR 1313.

Mr. Bordine also pointed out that the Company did perform a cost-benefit analysis to justify the Grid Capabilities investments provided in Section VII of the Company's EDIIP. See Exhibit A-111 (TJS-1). Mr. Bordine specifically explained some of these benefits as follows:

“The SAIDI improvement from grid automation and advanced technologies investments is estimated at 12 to 20 SAIDI minutes over the Company's five-year plan. The estimated 12 to 20 SAIDI minutes above used DSCADA and ATR automation loop deployments as a projection due to the uncertainties resulting from newer devices being tested and expected from future applications (i.e., line sensors, ADMS). The largest SAIDI benefit from Grid Capabilities: Automation investments are from ATR automation loops and DSCADA. These two investments make up the largest percentage of spend in Grid Capabilities: Automation.

“Also, the grid automation and technology investments support more than reliability benefits. The Company's CVR program in Case No. U-20165 will provide benefits of 4% peak demand reduction (111 MW Reduction by 2028) and 2% annual energy reduction (256 MWh Reduction by 2028). These reductions lead to avoided capital savings for the Company and energy savings for the customer because new generation capacity is avoided. The CVR program benefits are dependent on the grid automation and advanced technologies.” 4 TR 1313-1314.

Thus, for the reasons discussed above, Mr. Coppola's criticisms regarding a cost-benefit analysis for Grid Capabilities should be rejected. The Company has completed robust cost-benefit analyses for the components of Grid Capabilities. The Company's proposed investments are

reasonable and prudent investments which improve customer reliability and system optimization and should be approved by the Commission.

Mr. Coppola's third criticism erroneously concludes that the Company's Grid Capabilities investments are premature. There is no valid basis to support this conclusion. The Company's Grid Capabilities deployments are delivering customer benefits and represent proven solutions in the utility industry. 4 TR 1314. Mr. Bordine explained that, with respect to the Company's current deployment of Grid Capabilities - Automation, the Company has saved 14.4 million customer minutes from January 2015 through September 2018 (corresponding to 8.0 SAIDI minutes). 4 TR 1314. The Company's Grid Capabilities deployments for Automation and Advanced Technology are also considered "mostly mature" from the US Department of Energy's "MODERN DISTRIBUTION GRID Volume II: Advance Technology Maturity Assessment" document, pages 39, 43, 50, and 55. 4 TR 1314. Mr. Bordine explained that the distinction of "mostly mature" means that "multiple product vendors are providing commercially available technology products and support to multiple customers." 4 TR 1315.

Furthermore, the Company has prudently learned from other deployments of this technology around the country before beginning its own deployments. An example of this is the Company's deployment of ADMS and ESME.² 4 TR 1315. Mr. Bordine explained that, for more than a decade, utilities have been implementing the components of ADMS as individual applications and from separate vendors. 4 TR 1315. However, the cost to maintain software interfaces, upgrades, and training across different product vendors drove the industry to move toward a single platform due to the similar operational needs of each application (i.e., requiring

² ADMS is a single software platform that includes three major components which are SCADA, Distribution Management System ("DMS"), and Outage Management System ("OMS"). 4 TR 1315. ESME is a category that will support the ADMS applications and improve processes in the areas of distribution planning, design, and operations. 4 TR 1198.

an electric connectivity model). 4 TR 1315. The Company prudently reacted to this trend and completed a cost-benefit analysis of having a combined ADMS versus separate SCADA, Distribution Management System (“DMS”), and Outage Management System (“OMS”) in 2015. 4 TR 1315. Mr. Bordine explained that the results of the analysis showed the cost of a combined platform for these components has a better net present value (“NPV”) due to the reduction in software interfaces, upgrades, operational efficiencies, and training requirements. 4 TR 1315. This cost-benefit analysis was provided to the Attorney General in 20134-AG-CE-287, and provided as Exhibit A-173 (AJB-24).

Another example of the Company learning from other utilities relates to the implementation of the DMS component of ADMS. 4 TR 1315. Other utilities have implemented a DMS component prior to having an accurate three-phase electric connectivity model in place. 4 TR 1315. Mr. Bordine explained that, to avoid this result, the Company is implementing ESME which will enhance the Company’s electric system model accuracy and provide greater connectivity and spatial accuracy of the connected assets. 4 TR 1315. This level of quality is required for distribution applications that include power line power flows, CVR, and FLISR. 4 TR 1315. Furthermore, Mr. Bordine explained that, in addition to improving the accuracy of the Company’s electric distribution model, the Company is also collecting connectivity down to the point of customer connection. 4 TR 1315-1316. Utilities with increasing customer DER are finding it a requirement to model down to this level for DER planning and DER integration. 4 TR 1316.

At 6 TR 2787, Mr. Coppola takes issue with the Company’s implementation of FLISR. Mr. Coppola states that from the description provided by the Company “it appears that the [First Energy and Duke Energy] have recently implement a limited FLISR network and not the broader

approach envisioned by the Company.” Mr. Coppola’s understanding is incorrect. While First Energy and Duke Energy do have limited FLISR installations, Mr. Coppola fails to consider that the Company’s equipment types and operational capabilities are also limited. 4 TR 1316. Mr. Bordine specifically explained that the Company’s implementation of FLISR closely resembles that of First Energy and Duke Energy in that the Company is choosing deployment sites strategically based on the specific benefit to the affected distribution circuits, rather than a more distant goal of 100% system penetration. 4 TR 1316. This approach ensures an optimal reliability and efficiency benefit for the dollars invested in these projects. 4 TR 1316. While the Company has a limited implementation of FLISR, Mr. Bordine also pointed out that other utilities, such as Alabama Power, are implementing system-wide FLISR deployments. 4 TR 1316.

Therefore, Mr. Coppola’s claim that the Company’s Grid Capabilities investments are premature should be rejected. The Company has prudently learned from other utilities implementing Grid Capabilities components around the country and has designed its own implementation of these technologies to provide the greatest amount of benefit to customers.

For the reasons discussed above, Mr. Coppola’s proposed \$45.3 million disallowance to historically incurred Grid Capability expenditures between 2015 and 2017 and proposed reduction to projected 2018 and 2019 costs in the amount of \$34.8 million and \$58.1 million, respectively, should be rejected. Mr. Coppola’s conclusions regarding the benefits and maturity of these investments are without merit and unsupported in the record. Mr. Coppola’s disallowance of \$45.3 million is particularly extreme and punitive given the fact that the Commission has previously approved the recovery of Grid Capabilities (also referred to as Grid Modernization) expenditures in electric general rate cases, Case Nos. U-17990 and U-18322.

Since the Commission has previously approved the recovery of these expenditures, it is unreasonable to now disallow historic Grid Capabilities expenditures incurred between 2015 and 2017 on the basis that they are premature, as Mr. Coppola proposes. The Company's proposed Grid Capabilities Automation and Advanced Technology expenditures should be approved by the Commission because they are reasonable and prudent and have been extensively supported by the Company in the record.

d. Areas Of Dispute With The Michigan Environmental Council/Natural Resources Defense Council/Sierra Club/Ecology Center/Michigan Energy Innovation Business Council

In 2016, the Company produced its most recent line loss study, the 2016 Loss Study Report, which was later revised. Exhibit A-29 (JRA-14) Revised. The Line Loss Study allocates system energy and demand losses among the various components of the system by calculating a percentage loss factor for each component. 5 TR 1947. Based on this information, updated loss calculations are used for determining 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. 5 TR 1948. The loss factor for the distribution primary system is calculated using average data from 400 representative distribution primary circuits. *Id.* 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. *Id.*

In commenting on the Company's Cost-of-Service Study ("COSS"), the Michigan Environmental Council ("MEC")/Natural Resources Defense Council ("NRDC")/Sierra Club ("SC")/Ecology Center ("EC")/Michigan Energy Innovation Business Council ("MEIBC") witness Douglas B. Jester indicates that the Company should be required to include, in future

COSSs, the use of loss factors specific to allocators such as annual energy, energy on-peak, energy off-peak, energy on-peak summer, energy off-peak summer, energy on-peak non-summer, energy off-peak non-summer, critical peak energy, and class peak used. 6 TR 2632-2633. However, the Company is unable to provide the requested information. The data used to calculate the energy and demand loss factors in its annual electric system loss study is not sufficiently granular to develop seasonal or on-peak and off-peak loss factors for all customer voltage levels. 5 TR 1990. Company witness Anderson testified that “energy losses for Primary LVD lines are calculated from data produced by modeling a sample set of Primary LVD circuits at nine different system gross load levels to produce an annual average energy loss factors.” As such, the Primary LVD energy loss factors specific to the allocators mentioned cannot be calculated. Additionally, the Secondary LVD energy loss factor is calculated from the amount of total system energy loss remaining after all other system component losses are allocated. 5 TR 1990. Thus, only the annual Secondary LVD energy loss factor can be calculated. Therefore, the Company is unable to provide Mr. Jester’s requested information.

e. Areas of Dispute With The Cities Of Flint And Grand Rapids

In his testimony, Cities of Flint and Grand Rapids witness Jester makes a variety of recommendations related to the Company’s Streetlighting Program and spending. For the reasons discussed below, Mr. Jester’s recommendations should be rejected.

Mr. Jester’s first recommendation suggests that the Company should offer an adjustment to customers who were early adopters to the Light Emitting Diode (“LED”) conversion process. 6 TR 2747. This recommendation should be rejected because it is unreasonable and based on a misunderstanding of a discovery response. Discovery response 20134-FGR-CE-407, provided as Exhibit FGR-4, which states that the Company will absorb the additional contribution

requirements when customers elect to install LED streetlighting on new business street light jobs. 4 TR 1304. Mr. Jester has misinterpreted this response, which focuses on new business streetlighting, by comparing it to the conversion process related to MV street lights that certain customers have elected to perform. 4 TR 1304.

Mr. Bordine explained that, contrary to Mr. Jester's understanding, the conversion charging for upgrading existing street lights to LED has not changed as a result of Case No. U-18322 except for the lone instance of when customers elect to replace their MV street lights with LEDs. The result of the proposal approved in Case No. U-18322 was to modify the existing MV Program beginning in 2018. 4 TR 1305. Mr. Bordine explained that MV conversions are different than when a customer elects to convert other light types to LED street lighting because the Department of Energy efficiency requirements forced manufacturers to stop making MV fixtures since the new requirements could not be met using MV lights. 4 TR 1305. Since this was no fault of the Company's customers, the Company has been replacing MV at no charge to the customers for approximately nine years. 4 TR 1305. MV conversion to LED is now available in this program for free conversion as part of the Commission's approval in Case No. U-18322. 4 TR 1305.

Mr. Jester further alleges that LED conversion costs are too high and references discovery question 20134-FGR-CE-405, provided in Exhibit FGR-8, as support. Mr. Jester again misinterprets the Company's discovery response in forming his conclusion. In his calculation, Mr. Jester has improperly added a loaded cost and a direct cost together and compared it with his own cost which is neither identified as loaded or direct. 4 TR 1305. Mr. Bordine explained that, without analyzing the many factors that go into a full scale conversion of a system such as the type of material used, crewing resources used, location of

work, and field conditions, one cannot accurately compare the cost to convert a street light system. 4 TR 1305.

Next, Mr. Jester states that the Company's LED street light maintenance plan is deficient and that by installing lights with a seven-pin receptacle, it would enable installation of sensor equipment and wireless communication nodes that would report light status automatically and support other functions. 6 TR 2750-2751. Mr. Bordine explained that the Company sees opportunity in innovation to improve outage identification on street lights and is planning for the future by including seven-pin receptacles on LED fixtures, when available. 4 TR 1306. However, installing such a system would require new software systems and upgrades to manage the data coming in from the lights. 4 TR 1306. Mr. Jester does not fully address or analyze the added cost to provide the service that he recommends. 4 TR 1306. Mr. Jester's claim that such technology carries a "very modest cost" does not fully account for the all of the requirements needed to implement such a system. 4 TR 1306. Mr. Bordine explained that when fully considering such requirements, costs would instead be higher than implied by Mr. Jester, and in contrast to the Company's objectives to keep customer costs low. 4 TR 1306-1307.

Finally, Mr. Jester suggests that the Company should coordinate its approach to municipal streetlighting by leveraging "in-house lighting expertise" at cities in crafting and revising Company standards and concludes that these efforts would bring down costs. Mr. Jester's recommendation should be rejected because it is unnecessary and potentially extremely burdensome. Mr. Bordine explained that the Company has a team dedicated to maintaining Company standards by monitoring future technologies, ensuring new technologies are safely vetted across multiple sources, and providing equivalent lighting that has been competitively bid to provide fairness to all of the Company's 800 plus communities. 4 TR 1307.

Furthermore, given that the Company serves 800 plus communities with streetlighting, Mr. Jester's proposal would be extremely onerous to implement. 4 TR 1307. Mr. Bordine further pointed out that Mr. Jester fails to establish how the proposed coordination would provide any improvement in the Company's service and also fails to establish a money-saving element that would benefit the customers. 4 TR 1307.

2. Fossil And Hydro Generation Capital Expenditures

a. Overview Of Test Year Capital Expenditures

(i.) Total Environmental And Non-Environmental Capital Expenditures

Company witness John P. Broschak, Vice President of Generation Operations and Compression, testified concerning Consumers Energy's Fossil and Hydro Generation capital expenditure amount and supported the reasonableness of the expenditures. 7 TR 3196-3228. Exhibit A-12 (JPB-3), Schedule B-5.1, detailed the capital expenditures proposed for inclusion in the Company's rate base for the projected bridge and test years. Mr. Broschak testified in support of Company capital expenditures for Fossil and Hydro Generation in the amounts of \$177.7 million for 2017, \$172.6 million in 2018, and \$168.7 million in 2019. 7 TR 3197; Exhibit A-12 (JPB-3), Schedule B-5.1, page 1. These amounts included \$13.4 million in contingency in 2018 and \$18.4 million in contingency in 2019. 7 TR 3200. Staff recommended that the Commission disallow all contingency expenditures. 6 TR 2417. While Consumers Energy continues to believe that it is appropriate to include contingency costs in projected capital expenditures (see 7 TR 3201), the Company recognizes that the Commission has recently prohibited recovery of contingency expenditures in the Company's general rate cases, and as such the Company is not contesting Staff's recommended disallowance of contingency expenditures in this case.

Mr. Broschak testified that maintaining plant safety, reliability, and compliance with regulations are the major drivers of capital expenditures for the generating plants. 7 TR 3196. Mr. Broschak provided a detailed explanation of these capital expenditures. See 7 TR 3202-3228. While the Company detailed its planned capital projects, it is possible that changes could be made to scheduled outages and forecasted capital expenditures. This is due to the fact that the Company often forecasts future actions and expenditures based on currently available information, which occurs many months before the work is completed. 7 TR 3199. Changes to forecasted capital projects may occur due to contractor availability, parts availability, changes in regulations, design changes, outage scope changes, changes in unit condition, and spot market prices. 7 TR 3199. While the forecasted capital projects may change, the Company has a history of prudent capital investments in its generating facilities, which have been consistently approved by the Commission. 7 TR 3199.

The Company's projected Fossil and Hydro Generation capital expenditures are being undertaken for the benefit of customers. As discussed in the testimony of Mr. Broschak, many of these expenditures will improve plant capacity and reliability, which helps shield customers from the varying-priced spot power market. 7 TR 3228. The Company's requested Fossil and Hydro Generation capital expenditures are reasonable and prudent and should be approved by the Commission.

(ii.) **Explanation Of Required Environmental Capital Expenditures**

Consumers Energy witness Heather A. Breining presented testimony describing the environmental regulations affecting the Company's electric generating fleet, the cost of compliance with those regulations, as well as the timing and justification for the investments made to ensure the Company's regulatory compliance. 5 TR 1999-2020. Ms. Breining

explained that the Company’s fossil-fueled Electric Generating Units are subject to a number of complex and overlapping air regulations intended to reduce the emission of air contaminants. 5 TR 1999. In addition, the Company is also subject to a number of environmental regulations related to water and waste regulation. 5 TR 1999. The Company’s requested rate recovery in this proceeding includes costs incurred for compliance with the following environmental regulations:

Air Quality Regulations

	Regulation	Acronym	Controlled Pollutant	Compliance Date
a.	Cross-State Air Pollution Rule	CSAPR	NO _x , 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.

Water Quality Regulations

	Regulation	Acronym	Controlled Pollutant	Compliance Date
d.	Clean Water Act §316(b)	316(b)	Fish Protection	2018-2022
e.	Steam Electric Effluent Guidelines	SEEG	Effluent	2020-2023

Coal Combustion Residuals (Waste) Regulations

	Regulation	Abbreviation	Controlled Pollutant	Compliance Date
f.	Resource Conservation Recovery Act	RCRA	Coal Combustion By-Product	2018

5 TR 1999.

Ms. Breining provided detailed explanation of the nature, history, and current status of each of these currently effective regulations. 5 TR 2000-2016. She also explained the nature and status of the Environmental Protection Agency’s (“EPA”) Clean Power Plan, which was stayed pursuant to a February 9, 2016 Order of the United States Supreme Court pending judicial

review of that EPA regulation. On October 16, 2017, the EPA published a proposal to repeal the Clean Power Plan.³ 5 TR 2001-2002.

Consumers Energy presented its Air Quality Compliance Strategy (“AQCS”) in the Company’s electric rate case, Case No. U-17735. Cost recovery was approved in the Commission’s November 19, 2015 Order in that case. 5 TR 2002. Ms. Breining testified that installation of the entire suite of AQCS projects is nearly complete, and that there are no projected AQCS expenditures in the test year. 5 TR 2003. Exhibit A-54 (HAB-1) sets forth actual 2017 and projected 2018 AQCS expenditures.

Ms. Breining also explained the Company’s regulatory compliance strategy and associated costs for waste related to Coal Combustion Residual (“CCR”) management under the Resource Conservation Recovery Act (“RCRA”). 5 TR 2003-2006. In December 2016, Congress enacted the Water Infrastructure Improvements for the Nation (“WIIN”) Act. 5 TR 2004. The WIIN Act provides authority for state implementation of coal ash management through a state permit program, which supplants the existing enforcement mechanism that relied on citizen lawsuits. The State of Michigan is currently discussing with stakeholders how to best implement a state program. 5 TR 2004. The Company plans to implement the bulk of CCR management requirements under RCRA by the end of 2019. 5 TR 2005. As indicated in Exhibit A-55 (HAB-2), Consumers Energy expects to complete the capital investments related to complying with RCRA prior to the test year. 5 TR 2006.

Ms. Breining explained the Company’s compliance strategy for water environmental regulations required by Section 316(b) and the Steam Electric Effluent Guidelines (“SEEG”)

³ Ms. Breining explained that the Company continues to monitor regulatory activity regarding greenhouse gas emissions. The Company is not seeking recovery in this proceeding of costs related to greenhouse gas emissions compliance. 5 TR 2002.

Rule. 5 TR 2006-2016. Exhibit A-56 (HAB-3) sets forth the Company's capital investments related to Section 316(b), and Exhibit A-57 (HAB-4) sets forth the Company's capital investments related to SEEG compliance, neither of which includes any test year expenditures. 5 TR 2009, 2015. For Section 316(b), the Michigan Department of Environmental Quality's final determination on Best Technology Available for minimizing adverse environmental impact is not expected until 2019. Thus, it is unlikely that any substantial work will occur in 2019, and the Section 316(b) expenditures originally planned for 2019 have been delayed to 2020. 5 TR 2009. For SEEG compliance, the EPA is expected to establish a new rule making related to effluent limitation in 2019. Thus, as with Section 316(b), the likelihood of substantial SEEG compliance work occurring in 2019 is low, and the SEEG expenditures originally planned for 2019 have been delayed to 2020. 5 TR 2014-2015.

The costs associated with the foregoing programs are reasonable and prudent to achieve compliance with state and federal environmental requirements.

b. Reply To Staff Regarding D.E. Karn Avoidable Expenditures

Company witness Broschak presented potential impacts to the Company's capital expenditure plan at D.E. Karn ("Karn") Units 1 and 2 and J.H. Campbell ("Campbell") Units 1 and 2 (collectively, the "Medium 4") in the event of the early retirement of any of these units in the years 2021 or 2023. 7 TR 3221-3222; Exhibit A-61 (JPB-4). In the scenario where Karn Units 1 and 2 are retired in 2023, Mr. Broschak identified \$2,719,000 in capital expenditures that the Company could potentially avoid making in the event the units are retired in 2023. 7 TR 3223; Exhibit A-61 (JPB-4). Staff witness Raushawn D. Bodiford recommended that since the Company is proposing to retire Karn Units 1 and 2 in 2023 in the Company's IRP proceeding,

the \$2,719,000 in capital expenditures identified as avoidable in that retirement scenario should be removed from the test year capital expenditure projections in this case. 6 TR 2412.

While the Company recognizes that it has proposed to retire Karn Units 1 and 2 in 2023 in its pending IRP proceeding, Case No. U-20165, the Commission has not yet approved the Company's IRP. As a result, it would be premature for the Commission to disallow capital expenditures that would be avoidable in a 2023 retirement scenario. 7 TR 3255. As Mr. Broschak testified, whether the expenditures identified as avoidable will in fact be avoided may depend on the progress of the IRP proceeding. 7 TR 3255. The Commission should not adopt Staff's recommendation to remove \$2,719,000 in capital expenditures for Karn Units 1 and 2 prior to the Commission's approval of the Company's IRP.

c. Areas Of Dispute With The Attorney General

(i.) Actual Expenditures Through Seven Months Of 2018

Attorney General witness Coppola recommended the removal of \$7.7 million from the Company's 2018 forecasted generation capital expenditures. 6 TR 2792. Mr. Coppola arrived at his recommendation by subtracting the actual generation capital expenditures through the first seven months of 2018 in the amount of \$92.2 million from the Company's capital spending forecast through the same seven months of 2018 in the amount of \$99.9 million. 6 TR 2791-2792. Mr. Coppola argued that this "variance appears to reflect a level of spending in the forecast that is not materializing." 6 TR 2792.

The Attorney General's recommended reduction is not based on any identified concerns with specific 2018 expenditures. Rather, the Attorney General's recommended \$7.7 million reduction seeks to hold Consumers Energy accountable to spending precisely what was projected during the first seven months of 2018. Mr. Broschak testified that "[a]ctual monthly spending

can vary from the monthly projected cash flows for a variety of reasons, including movement of capital expenditures to later in the year or into the next year.” 7 TR 3256. It is unreasonable to reduce projected 2018 capital expenditures based solely on the amount of expenditures made through just half of the year. 7 TR 3256.

Based on Mr. Coppola’s reasoning, the Commission would be required to approve capital expenditures *above* the filed projections where the Company spends *more than* projected through half the year. 7 TR 3257. The Company disagrees with Mr. Coppola’s contention that an adjustment to capital expenditures in a rate case proceeding is appropriate solely as a result of the Company’s expenditures through half the year. 7 TR 3257. The Commission should not adopt the Attorney General’s recommendation.

(ii.) Distributed Control System

The Company’s projected capital expenditures include upgrades to the Distributed Control System (“DCS”) and associated training simulators at certain of its units to maintain reliability and minimize vulnerability to intrusion. See 7 TR 3203, 3205, 3209. DCS is the brains of the power plant, allowing plant operators to monitor and control the numerous and complex operating systems at the plant, including systems related to fuel, boiler, steam, turbine, and AQCS. 7 TR 3257. DCS components are replaced and software upgraded approximately every four years to avoid end-of-life failures and to remain current with virus protection and software patches. See Exhibit AG-13, pages 1, 3, 5, and 10.

Attorney General witness Coppola recommended the reduction of \$8.1 million in capital expenditures related to the DCS upgrade at the Campbell and Karn facilities. 6 TR 2794. Mr. Coppola argued that the “four-year upgrade cycle appears to be too frequent given the fact that the Company has not experienced any incidents or failures during the most recent three years,” and that an upgrade is “premature without more concrete evidence of failures.” 6 TR

2793-2794. Mr. Coppola's recommendation is based on the premise that the Company should wait for a DCS failure to occur before upgrading the DCS. Consumers Energy disagrees.

Consumers Energy operates its plants with a goal that none of its plants experience DCS failures, and the fact that no DCS failures have occurred within the previous three years is consistent with that goal. 7 TR 3259-3260. The consequences of a DCS failure include: (i) the plant tripping offline, leading to lost generation and the need to purchase replacement power; (ii) equipment damage resulting in unplanned outages; (iii) unauthorized access; and (iv) unsafe working conditions for employees. 7 TR 3259. While Mr. Coppola did not indicate how many DCS failures would be acceptable before the Company should upgrade the DCS, his position that the Company should wait for a DCS failure before upgrading the DCS necessarily increases the risk of failures, equipment damage, unauthorized access, and unsafe working conditions as the result of a DCS failure.

The four-year DCS upgrade cycle is based on the Original Equipment Manufacturer ("OEM") Product and Software Support Policy, which states that software support is limited to five years. 7 TR 3259. Consumers Energy's four-year cycle allows for potential delays in the upgrade process. 7 TR 3259; Exhibit A-141 (JPB-9). The projected DCS expenditures support the continued successful operation and upgrade of the Company's DCS consistent with the OEM's software support. 7 TR 3260. The Commission should approve the \$8.1 million in DCS expenditures.

(iii.) Jackson Plant

Attorney General witness Coppola recommended a reduction of \$2.5 million in 2018 and \$1.5 million in 2019 in Jackson Plant expenditures that the Company identified as expenditures for "Extra Work Expected." 6 TR 2794. Mr. Coppola characterized these expenditures as "uncertain" and "speculative." 6 TR 2795. Mr. Broschak testified that the Company identified

these projects as “Extra Work Expected” because they represent work that is not covered by the Jackson Plant’s Long Term Service Agreement (“LTSA”) with General Electric, and are thus considered “extra work” with respect to the LTSA. 7 TR 3260. The “extra work” to be completed in 2018 and 2019 includes “replacement of the Variable Stator Vane bushings, actuator, seals, and rigging; replacement of the Low Pressure compressor shroud, igniter plugs, and Foreign Object Damage inlet screen; and exchange of the stage 2 High Pressure nozzle.” 7 TR 3260-3261. These projects are not “uncertain” or “speculative,” but rather are projects the Company fully expects to perform. 7 TR 3261. The Commission should not reduce the projected Jackson Plant expenditures.

(iv.) **Ludington Pumped Storage Facility Overhaul And Upgrade**

Consumers Energy is continuing the multi-year overhaul and upgrade of the six generating units at the Ludington Pumped Storage Facility (“Ludington Plant”). As part of the overhaul and upgrade, the major components of the generating/pumping units have been redesigned and will be replaced using materials intended to lengthen operating life, reduce operating costs, and improve operating efficiencies. 7 TR 3216. The new, higher efficiency design results in more energy available to generate with the same pond level. 7 TR 3216-3217.

Attorney General witness Coppola questioned whether it is “economically advantageous to continue to expand the [Ludington] facility and invest hundreds of millions of dollars.” 6 TR 2796. Mr. Coppola recommended that the Company present an updated cost/benefit analysis for the Ludington Plant overhaul and upgrade “to justify capital investments from 2019 to future years.” 7 TR 2797. The updated analysis requested by Mr. Coppola is not necessary.

The Company originally performed a cost/benefit analysis of the Ludington Plant overhaul and upgrade which showed a net savings through 2030 of both the upgrade and

overhaul, with those savings increasing through 2058. 7 TR 3261-3262; Exhibit AG-15, page 6. The Company reasonably pursued the overhaul and upgrade, and the Company has included, and the Commission has approved, the capital expenditures relating to the overhaul and upgrade in a number of rate case proceedings. See, for example, MPSC Case No. U-16794, June 7, 2012 Order, pages 19-20. The Company expects to complete the overhaul and upgrade of the fifth unit in early 2019, the project is currently under budget, and the performance of the upgraded units has met or exceeded the design specifications. 7 TR 3261-3262. The unit improvements resulting from the overhaul and upgrade are providing customer value. With five of the six unit upgrades soon to be complete, performing an updated cost/benefit analysis would provide little insight in determining whether the Company should complete the upgrade of the final Ludington Plant unit. 7 TR 3262. Accordingly, the Commission should not require the requested cost/benefit analysis.

d. Areas Of Dispute With MEC/NRDC/SC

MEC/NRDC/SC witness Tyler Comings recommended that the Commission “not approve any non-essential new capital investments in Karn Units 1 and 2 in this case” and that the “[f]urther capital investments in these units should be re-evaluated after a final retirement decision has been made.” 6 TR 2717. The Karn Units 1 and 2 expenditures that the Company has included in this case are “essential” to support the continued effective, safe, and reliable operation of Karn Units 1 and 2 until their 2031 retirement date. 7 TR 3266. As discussed, the Company has identified \$2.7 million of these expenditures as avoidable in the event the Commission approves the 2023 retirement of Karn Units 1 and 2 in the Company’s IRP. And the Company has already deferred millions of dollars in Karn Units 1 and 2 capital expenditures since March 2016 in order to optimize customer value. 7 TR 3266; Exhibit A-142 (JPB-10). As it has historically done, the Company will continue to evaluate Karn Units 1 and 2 expenditures

in order to maximize customer value and ensure the highest priority projects are completed.
7 TR 3266.

In this case, the Commission should approve the capital expenditures that the Company has projected as essential for the safe and reliable operation of Karn Units 1 and 2. Karn Units 1 and 2 expenditures that will occur after the test year will be considered in subsequent rate case proceedings.

3. Facilities Capital Expenditures

a. Company's Position

Company witness LaTina D. Saba (formerly LaTina D. Johnson) supported the Company's capital expenditures related to Electric Operations Support. Electric Operations Support provides support to the Company by acquiring, constructing, and maintaining assets required to operate the functional areas of the business, and specifically consists of: (i) Fleet Services, (ii) Facility Operations, (iii) Real Estate, and (iv) Administrative Operations. 5 TR 2138. Fleet Services is addressed by Company witness Bruce K. Straub.

Ms. Saba sponsored Exhibit A-12 (LDJ-1) which provided the Company's projected Electric Operations Support capital expenditures. These expenditures are broken down into two cost categories: Asset Preservation and Computer and Other Equipment. Ms. Saba explained the projects which support these expenditures as follows:

“Asset Preservation of the Company's facilities investments includes new construction, remodeling of existing facilities, emergent work, lifecycle replacement of infrastructure, equipment and system failures . . .

“The Company's Asset Preservation of Facilities investments includes: (i) infrastructure investments; (ii) upgrades and maintenance; and (iii) purchase, new construction, and renovations . . .

“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 . . .

“Upgrades and maintenance capital expenditures include capital expenditures such as those made to parking lots, roofs, and elevators at various building and plant sites . . .

“The final component of the facilities investment plan is the purchase, new construction, and/or renovation of service centers to support operations across the state of Michigan. An example of this is the ongoing renovation at the Parnall Road Complex located in Jackson, Michigan . . .

“Computer and Other Equipment includes the purchase of miscellaneous printers, mechanical equipment, print production equipment, and wellness equipment.” 5 TR 2139-2140.

Based on these projects, Ms. Saba explained that the Company is projecting total Electric Operations Support capital expenditures to be \$21,363,000 for 2018, and \$33,540,000 for 2019 for a two-year total of \$54,903,000 as set forth in Exhibit A-12 (LDJ-1), Schedule B-5.2, line 9, column (c); line 9, column (d); and line 9, column (e), respectively.

b. Areas Of Dispute With The Attorney General

Attorney General witness Coppola, in his testimony, challenged the Company’s plan to invest in the construction of a new office building in Grand Rapids, wherein the Company plans to spend \$1 million in 2018 and \$10 million in 2019 for construction. This information was

provided to the Attorney General in discovery response 20134-AG-CE-601 (Exhibit AG-19). Mr. Coppola questioned the necessity of the new build rather than a potential lease of office space. 6 TR 2803. Based on discovery response 20134-AG-CE-601 (Exhibit AG-19), Mr. Coppola tied the new build only to the Company's grid modernization project. As a result, he argued that "[t]he real question is whether the grid modernization project should proceed at the level and pace that the Company has outlined . . . Until this program is better justified, it may be premature to build a new office building to house engineers working on grid modernization." 6 TR 2803. As a result, Mr. Coppola recommended an \$11 million disallowance in capital expenditures forecasted by the Company between 2018 and 2019. 6 TR 2803-2804. As explained in the testimony and exhibits of Ms. Saba in this matter, however, this disallowance is not supported and should be rejected by the Commission.

As Ms. Saba explained in rebuttal testimony, the new building will not be limited to grid modernization personnel and will provide benefits beyond the Grand Rapids area. 5 TR 2149. In fact, she indicated that the new build project in Grand Rapids "strategically aligns with our Facilities' plan to consolidate our existing Grand Rapids Service Center and relocate a majority of those employees to this new site." 5 TR 2149. As Ms. Saba further stated, "[t]here will be engineers, call center representatives, and other professionals from other departments within the Company (i.e., customer experience, real estate, governmental relations, etc.) that are part of this relocation effort." 5 TR 2149. Exhibit AG-41 (discovery response 20134-AG-CE-715) demonstrates the breakdown of employees and departments to occupy the new Grand Rapids location. Finally, as Ms. Saba indicated in rebuttal, based on the feasibility analysis conducted by the Company, using criteria such as number of employees, number of parking spaces, office space requirements, construction, and turn-key timelines, the Company found that there is not

sufficient existing office space available for purchase or lease in the Grand Rapids area to accommodate the Company's needs. 5 TR 2145-2148. Thus, Ms. Saba fully supported the new building project in Grand Rapids, and rebutted Mr. Coppola's objections to the new building project, and Mr. Coppola's proposed \$11 million disallowance should be rejected.

4. Fleet Services Capital Expenditures

a. Company's Position

Company witness Straub, Director of Fleet Services, presented the Company's projected Fleet Services capital expenditures. 5 TR 1501-1517; Exhibit A-12 (BKS-1), Schedule B-5.2. The Company's total projected investment is \$13,327,000 in 2018 and \$31,862,000 in 2019. 6 TR 1501; Exhibit A-12 (BKS-1), Schedule B-5.2. As discussed in more detail below, the Company's Fleet Services capital spending is projected to increase in 2019, when compared to 2018, because the Company is proposing to move to an optimal fleet life cycle between five and eight years versus the current fleet life cycle of 12 to 15 years. 5 TR 1506.

Mr. Straub explained that Fleet Services provides support to the Company by acquiring, maintaining, and ensuring the safe operation of all vehicle equipment assets required to operate the functional areas of the business. 5 TR 1501. Mr. Straub also provided additional details regarding Fleet Services as follows:

“Fleet Services manages a fleet of over 7,000 units through their first, second, and in some cases third life cycle for use in daily operational work. The Fleet organization consists of maintenance operations, acquisition/disposition, regulatory and technical management, and strategy/data. Specific to the Company's electric business, Fleet Services' purpose is to ensure that the Company's Electric Operations Department can leave our service centers every day to quickly and efficiently serve our customers in their effort to meet Customer On Time Delivery ('COTD'), Customer Average Interruption Duration Index ('CAIDI'), System Average Interruption Duration Index ('SAIDI'), and all other response metrics. Fleet Services manages the Company's fleet using a balanced approach focused on quality, cost, and delivery. Fleet

Services has been extremely successful with our approach and provides great value to the Company's electric operations and customers." 5 TR 1501-1502.

Capital spending for Fleet Services is divided into two programs: Transportation Equipment and Other Equipment. 5 TR 1501. The cost categories within the Transportation Equipment program are: contractor, labor, materials, business expenses, and other (loadings, chargebacks). 5 TR 1501. Mr. Straub explained that the Company's Transportation Equipment investments include the purchase of vehicles, equipment, and trailers as part of the Company's fleet life cycle program. 5 TR 1503. Furthermore, Mr. Straub explained that Other Equipment includes tools and general vehicle maintenance equipment. 5 TR 1503.

The Company's 2018 Fleet Service capital spending levels, as provided in Exhibit A-12 (BKS-1), Schedule B-5.2, are based on recent spending levels in the 2017 historical year. 5 TR 1504. However, for the 2019 spending amount, the Company commissioned Utilimarc, a company which specializes in fleet benchmarking, analytics, telematics, and smart data management, to perform a life cycle study of the Company's fleet. 5 TR 1504. The study performed by Utilimarc is provided as Exhibit A-112 (BKS-2). Mr. Straub explained that Utilimarc has provided benchmarking to determine where the Company's fleet ranks among its peers and also serves as a strategic thought partner to help the Company maximize fleet value. 5 TR 1511.

The Utilimarc study determined that the Company's current fleet life cycle was inadequate and leading to higher maintenance costs. By decreasing unit life cycle, there is a corresponding increase to the investments that the Company is required to make. However, the Company would also see a reduction in maintenance expense that it incurs by keeping older fleet

vehicles in working condition. 5 TR 1509. Mr. Straub addressed the current issues with the Company's fleet life cycle and the results of the Utilimarc study as follows:

“In previous years, Fleet Services’ request was based on a base amount for life cycle replacement and tooling. The Company’s current fleet life cycle for our highest cost, largest, and most critical units is 12 to 15 years before unit replacement on average. However, based on the study performed by Utilimarc, the Company has determined that the optimal life cycle for electric fleet asset replacement is between five and eight years on average, depending on unit type. In order to achieve the optimal life cycle, the total capital spending for Fleet Services would need to be between \$51.7 million and \$67.4 million for both electric and gas operations with gradual growth, due to inflation, over the next 10 years.” 5 TR 1506 (footnote omitted).

Therefore, for the 2019 test year, Fleet Services is requesting \$31.6 million to improve the life cycle of the Electric Operations fleet and \$254,000 for appropriate tooling and training. 5 TR 1506.

Mr. Straub provided extensive detail in his testimony concerning the impact of the current spending amounts and proposed spending amounts on the Company’s fleet life cycle. 5 TR 1507-1512. Mr. Straub also explained how increased spending and an appropriate fleet life cycle ultimately reduce costs as follows:

“While Fleet Services has been able to maintain a balanced budget through reducing waste and inefficiency, the Company is reaching a tipping point where O&M costs will continue to increase if improvements are not made to the fleet life cycle investment plan. Given the fact utility fleets are recognized as being the most complex fleets across all industries, it is critical to reduce or eliminate back-in-service units (i.e., units retired to service after end of life cycle) due to the increased O&M expense required to maintain the unit. Additionally, it is critical to build a sustainable annual life cycle plan. When an appropriate life cycle model is not established and followed, O&M cost resulting from maintenance and major repairs elevate considerably and may become unpredictable. By increasing the capital spend on new trucks, trailers, and equipment, Fleet Services can effectively predict the

O&M cost year over year as the Company works back to an acceptable level of out-of-life-cycle units.” 5 TR 1509.

The life cycle model and the 2019 spend plan proposed by the Company in this case ensure the asset is fully utilized and disposed of before extraordinary O&M costs are incurred in year seven of operation and beyond. 5 TR 1509. The Company’s proposal also has the added benefit of providing safety features for the Company’s employees and increased intelligence and technology, as these items are now standard on new trucks and equipment. 5 TR 1510. Furthermore, the Company’s proposal will allow for the purchasing of universal fleet units with interchanging attachments which will allow the Company to provide better service to its customers at a lower cost. 5 TR 1510.

In addition to the above, Mr. Straub explained the breakdown of the Company’s proposed Fleet Services capital spending in this case. With respect to the Transportation Equipment category, Mr. Straub provided that:

“Nearly \$22.765 million of the spend plan is allocated towards our most critical electric units (Spec 89/96 - Electric Distribution Tandem Axle Bucket Trucks, Spec 77 – Electric Digger Derrick, Spec 64 – Electric Service Bucket Truck, and Spec 36 – Electric Meter Operations Truck). Additionally, roughly \$4.5 million dollars is allocated towards specialty equipment which allows our crews to perform higher complexity and more diverse work quicker (Spec E11/E15 – Rock/Frost Wheels (Chassis and Attachments), Spec E36 – Mini Flex Track, Spec T15 – Trailers and Tuggers). Additionally, the capital spend includes: contractor cost, business expenses, and other loadings/chargebacks incurred during the purchase of new units. The remaining \$4 million in funding is allocated to purchase support pickup trucks for additional crew resources, field leaders, engineers, supply chain, fleet, and several other organizations.” 5 TR 1512-1513.

Mr. Straub also explained the Company’s proposed spending in the Other Equipment category of Fleet Services capital expenditures, which includes tooling and other vehicle maintenance equipment required to repair and maintain new and old makes and models. 5 TR 1514. A driver

of these costs is the tooling required to maintain new fleet technology. 5 TR 1514. This tooling is necessary to keep O&M costs under control. 5 TR 1514.

Finally, Mr. Straub detailed the benefits of the Company's proposed Fleet Services spending for 2019. 5 TR 1514-1517. Mr. Straub explained that consistent spending levels, as proposed by the Company in this case, will decrease out-of-life-cycle units, improve the Company's overall life cycle plan for fleet, and lower O&M costs annually. 5 TR 1514. Mr. Straub also explained that the Company's proposed Fleet Services spending levels would: (i) improve response times to the Company's customers; (ii) reduce the time to perform work in the field; (iii) provide a safer and more reliable unit to our operators; (iv) reduce the overall age of our fleet and operate within a single life cycle; (v) reduce and eventually eliminate the need for back-in-service units; and (vi) decrease the Company's overall fleet O&M expense (outside services, overtime, materials). 5 TR 1517.

b. Areas Of Dispute With The Attorney General

The Attorney General was the only party to oppose the Company's Fleet Services capital expenditures. Attorney General witness Coppola suggests that the Company's proposed Fleet Services spending level for 2019 is not justified and recommends the 2019 spending level be equal to the amount proposed for 2018. 6 TR 2808. For the reasons discussed below, the Attorney General's recommendation should be rejected.

In an attempt to support his recommendation, Mr. Coppola first argues that an increase to Fleet Services capital spending is not warranted because the Company currently has "excellent" fleet unit availability. 6 TR 2805. While Mr. Coppola's representation of the Company's fleet unit availability is correct, Mr. Coppola's attempt to use fleet unit availability to suggest that more investments are not necessary is flawed. Company witness Straub explained that unit availability does not demonstrate that the Company's fleet is not in deteriorating condition. 5 TR

1520. What the Company's current fleet availability indicates is that the Company is presently doing a tremendous job in keeping its aging, out-of-life-cycle fleet units on the road despite the deteriorating condition of these units. 5 TR 1520. Mr. Straub explained that unit availability is not related to the need to invest in new fleet units and also provided examples of how deteriorating fleet units are driving costs 5 TR 1521. Furthermore, Mr. Straub explained that technology advancements in today's fleet units lead to more frequent repairs and associated costs. 5 TR 1522. A shorter fleet unit life cycle, as proposed by the Company in this case, will help to avoid the extensive maintenance costs currently incurred by the Company to keep its fleet units in working condition.

Mr. Coppola's next argument suggests that the Company has not quantified how maintenance and repair costs have escalated in recent years. 6 TR 2806. This is not correct. Mr. Straub established that the Company's fleet maintenance costs have escalated in recent years and provided a chart at 5 TR 1524 which demonstrates the increased maintenance cost over the last 18 months since the Company formally started measuring critical unit availability. Mr. Straub explained that the total cost to maintain the Company's fleet is driving upwards to ensure that the Company can serve its customers in an appropriate manner. 5 TR 1523.

Mr. Straub also provided a second chart at 5 TR 1525 which illustrates the average operating cost per fleet unit based on age of unit. Mr. Straub explained that this chart demonstrates that maintenance costs gradually increase after the first year of operation and spike in years 2, 4, 9, 11, 14, and 16.⁴ 5 TR 1524. This demonstrates that as fleet units begin to age maintenance spending becomes more routine and the amount of spending increases. 5 TR 1524. The spikes in spending also show the incredible volatility in the cost to operate fleet units as the

⁴ The spikes in spending are related to the fact that there is typically a period where no spending is needed on a specific unit after a large maintenance project is completed. 5 TR 1524.

units age. 5 TR 1525. Mr. Straub explained that simply repairing units again and again in later years leads to more frequent and costly repairs in the future and that spending in this manner does not impact the longevity of fleet units in a prudent financial manner. 5 TR 1525.

Mr. Coppola also argues that safety features such as lane assist and blind spot monitoring do not justify additional spending. 6 TR 2806. What Mr. Coppola misses here is that the Company is not proposing to increase fleet investment just to acquire additional safety features on its vehicles. 5 TR 1527. The Company is instead proposing to increase Fleet Services investment because its fleet units are aging and requiring substantial maintenance costs due to a life cycle which is longer than the industry standard. 5 TR 1527. Mr. Straub explained that if the Company is able to implement investments which allow for a fleet life cycle consistent with industry standards, the Company will be able to purchase new fleet units to replace older, outdated units. 5 TR 1527. These new fleet units will include numerous standard safety features, including blind spot monitoring and lane assist, which will increase safety. 5 TR 1527.

Finally, Mr. Coppola argues that, according to a NPV analysis he conducted, the Company's 2019 Fleet Services capital spending proposal "does not create an economic benefit over the next 10 years." This argument should be rejected because Mr. Coppola's calculation and assumptions are flawed. Company witness Heidi J. Myers explained that Mr. Coppola's NPV calculation should not be relied on when evaluating the economic value of accelerating the retirement of fleet units, as the Company proposes to do in this case. Ms. Myers specifically explained that Mr. Coppola's calculation was flawed because he used a 2017 pre-tax cost of capital which did not include the impacts of tax reform and is therefore too high. 2 TR 351. Mr. Coppola also inappropriately compared the NPV of capital spend dollars to the NPV of O&M expense savings. 2 TR 351. Since customers pay the revenue requirement of capital

spending, any NPV analysis which compares capital spending to O&M expenses should include the revenue requirement of the capital spending. 2 TR 351. Mr. Coppola's calculation failed to determine the revenue requirement for the Company's proposed Fleet Services capital spending.

Ms. Myers further explained that Mr. Coppola's calculation is inappropriately limited to a 10-year span. This is problematic because when the revenue requirement of capital spending is compared to O&M savings, it is important to provide the revenue requirement and O&M savings for the life of the asset. 2 TR 352. The revenue requirement of an asset is at its highest in the initial years. For instance, in the later years of Mr. Coppola's calculation period, such as years seven through nine, Mr. Coppola includes the initial investment in fleet vehicles but does not show the entire life of the units purchased in these years. Therefore, it is misleading and inappropriate to complete a NPV analysis that cuts the analysis off at a point when the revenue requirement is at its highest for capital investments and the O&M savings realized over the remaining life of that asset are not incorporated. 5 TR 352.

In addition to these calculation errors, Mr. Straub also pointed out additional flaws in the assumptions made by Mr. Coppola in his calculation. Mr. Coppola extracted certain information from the Utilimarc study, provided as Exhibit A-112 (BKS-2), in developing his NPV calculation, provided as Exhibit AG-21. However, in extracting this information, Mr. Coppola failed to fully understand the Utilimarc study and the costs presented in that study. Mr. Straub explained that Mr. Coppola failed to consider that the Utilimarc study provides analysis and benchmarking based on the industry average of 28 utility companies across the United States. 5 TR 1528. The primary purpose of the Utilimarc study is to demonstrate that the industry average fleet unit life cycle of five to eight years is substantially less than the Company's current

fleet life cycle of 12 to 15 years. Furthermore this study demonstrates the investment costs required to allow the Company's fleet unit life cycle to be consistent with the industry average.

Furthermore, Mr. Coppola failed to properly consider the investment and maintenance costs provided in the Utilimarc study. Mr. Straub explained that, while the Utilimarc study is helpful to determining the appropriate fleet unit life cycle, investment, and a baseline for maintenance expense, the study should not be viewed as providing a ceiling for the Company's potential maintenance costs should the current fleet unit life cycle remain the same. 5 TR 1529. In fact, under the current fleet unit life cycle, Mr. Straub explained that the Company expects significantly higher maintenance costs than projected by Utilimarc. 5 TR 1530. For example, in 2027, the Company projects that maintenance costs under the current fleet unit life cycle could be double what Utilimarc has projected. See "Fleet Maintenance Expenses Analysis – 2018 – 2027" Chart at 5 TR 1530; Exhibit AG-21, column (2027), line 7. Thus, although the Utilimarc study has tremendous value from an investment and industry standard perspective, it is not appropriate to solely rely on the study to form conclusions regarding the Company's maintenance costs under the current fleet unit life cycle, as Mr. Coppola has done in his analysis.

Therefore, for the reasons discussed above, Mr. Coppola's recommended reduction to the Company's proposed 2019 Fleet Services capital expenditures should be rejected. The Company's proposed Fleet Services capital expenditures for 2019 should be approved as reasonable and prudent because they will allow the Company to implement a fleet unit life cycle which is consistent with industry standards and will also allow the Company to avoid incurring substantial fleet unit maintenance costs due to operating out-of-life-cycle fleet units.

5. Information Technology Capital Expenditures

a. Company's Position

Company witness Josh R. Hall, Executive Director of Information Technology (“IT”) Customer Experience and Operations, testified to the necessary capital expenditures for the IT Department. 2 TR 257-278. The IT Department “provides IT solutions and services including the identification, implementation, operational support, and maintenance of software solutions, computing, and communications infrastructure.” 2 TR 252. IT also provides “day-to-day operational support for each individual user of technology, whether that technology is a desktop, laptop, or mobile device, which includes ruggedized field devices, tablet computers, cell phones, smart phones, or other handheld devices.” 2 TR 252. Mr. Hall explained the software solutions provided by the Company’s IT department and how this benefits the Company and its customers as follows:

“Software solutions are business applications that automate and support business functions to support customer interactions in areas such as customer service and billing, work and asset management, outage management, payroll, supply chain, electronic mail, and document creation and management. The IT Department operates and maintains a full range of tools and computing infrastructure for the software applications utilized by the Consumers Energy workforce.” 2 TR 252.

Mr. Hall also explained that the IT department maintains the Company’s computing infrastructure which “consists of hardware and communications networks which are utilized by virtually all aspects of the Company’s operations.” 2 TR 252. “Hardware” consists of servers and data storage devices, workstations, printers, and mobile devices. Furthermore, “communications networks” refers to telephone and radio systems which enable voice, data, and wireless communications across the Company. Mr. Hall further explained that “[t]he Company also employs a private cloud to automate the deployment of virtualized computing infrastructure

on top of the previously mentioned hardware and networks, increasing the speed and quality of infrastructure deployment.” 2 TR 252.

In addition to explaining the role of the Company’s IT Department, Mr. Hall addressed how IT projects are prioritized, approved, and initiated. 2 TR 257. Specifically, Mr. Hall explained that:

“Technology projects are scored and ranked based on the business and customer value they provide, and the highest ranked projects that can be completed within budget are selected for implementation. The scoring occurs upon submission of a project idea and as the business case is solidified. Project vetting through IT and the affected internal business areas is repeated throughout the year as business objectives, Company goals, and customer needs for the upcoming year are solidified. Projects that do not demonstrate value through a business case are not selected, and these projects are sent for further analysis or eliminated outright. Company Board of Directors approval is not required as part of this selection process.” 2 TR 257-258.

Mr. Hall also detailed how the IT Department’s evaluation of IT projects benefits customers:

“Customer benefits are included in the project evaluation in several ways, and the inclusion of customer benefits in the evaluation process garners those projects higher rankings in the project prioritization list. Customer value is comprised of the project’s cost-benefit ratio and its expected impact on customer satisfaction as measured by J.D. Power Utility Customer Satisfaction Surveys. Feedback on the J.D. Power surveys results in projects to improve customer satisfaction in power quality and reliability, billing, payments, contact centers, and the Company website. In addition to the J.D. Power surveys, the Company receives daily Customer Experience Index (‘CXI’) scores on its contact centers and website. The CXI scores reflect if the customer’s interaction has met their needs, if the interaction was easy, and if the interaction was enjoyable. There are also free-form comment fields where customers can make suggestions for improvements or indicate application areas of concern. The Company monitors the comment section for patterns or repeated themes, and tailors system changes accordingly.” 2 TR 258.

Exhibit A-12 (JRH-2), Schedule B-5.6, provides a summary of the Company's actual and projected IT capital expenditures. For 2017, the Company incurred capital expenditures in the amount of \$64,627,000. For 2018, the Company projected capital expenditures in the amount of \$84,937,000. For 2019, the Projected Test Year, the Company projected capital expenditures in the amount of \$78,628,000. 2 TR 255. Exhibit A-84 (JRH-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. 2 TR 256. Furthermore, Exhibit A-85 (JRH-4) provides the costs, descriptions, benefits, alternatives, and other relevant project information for each individual project. 2 TR 258. The IT capital projects are grouped into the following categories: (i) Customer Experience and Operations; (ii) Asset Refresh Program ("ARP"); (iii) Data Center 2.0; (iv) Security; (v) Corporate and Enterprise; (vi) Engineering; and (vii) Generation and Field Operations. Exhibit A-85 (JRH-4) provides a detailed line-by-line analysis for each of the IT capital projects above. This analysis includes project name, project area, requested spending amounts, project description, alternatives considered, project scope/functionality, project benefits, and an implementation plan. 2 TR 259.

b. Response To Staff

Staff witness Lauren Fromm recommends IT capital expenditure reductions related to contingency costs as well as other IT project expenditures that the Company projects to incur in 2018, in the amount of \$2.2 million, and 2019, in the amount of \$6.671 million. 6 TR 2418. Ms. Fromm also makes recommendation with respect to the presentation of IT expenditures in the Company's future rate case filing. 6 TR 2422-2423. The Company is not contesting Ms. Fromm's contingency cost reduction and is also accepting Ms. Fromm's cost reduction for 2019. However, for the reasons discussed in more detail below, the Company opposes

Ms. Fromm's recommendation for costs expected to be incurred in 2018 and other recommendations regarding future rate case filings.

For the 2019 Projected Test Year, Ms. Fromm recommends a total IT capital expenditure cost reduction of \$6.671 million which consists of: a \$4.071 million reduction related to the Company's ARP – Storage project; a \$1 million reduction related to the Company's Legal – Archiving Tool for Email, Chat, File shares, and SharePoint project; and a \$1.6 million reduction related to the Company's Customer Experience Improvements project. The Company does not oppose Staff's proposed cost reductions. 2 TR 290. However, the Company reserves the right to submit these capital requests in future rate cases after more information has been gathered to bolster the project business cases. 2 TR 290.

With respect to Ms. Fromm's proposed reduction to 2018 IT capital expenditures, the Commission should not approve Ms. Fromm's recommendation in its entirety. Ms. Fromm's proposed 2018 reduction of \$2.2 million relates to the Company's ARP - Workstation Asset Management ("WAM") project. Mr. Hall explained that this project relates to the replacement of workstations, computers, laptops, and accessories and how the Company has recently consolidated the costs of this project into IT, as opposed to the individual departments of the Company that use these items, as follows:

“The IT Department has historically budgeted and purchased only replacement of workstations, computers, laptops, monitors, and accessories for all departments within the Company. Starting in 2018, all new purchases of workstations, computers, and peripheral equipment for the entire Company was consolidated into the IT department budget. This funding is in addition to the workstation replacement budget, and in attempting to maintain a specific line of sight to the budget figures for the added departments, dollars were placed in the ‘Other’ category within the Business Case - Project Tracking file. The dollars budgeted within the “Other” costs category is actually purposed for new purchases of computer hardware and equipment and is not just a contingency fund for the

project.” 2 TR 288.

Mr. Hall further explained that, contrary to Ms. Fromm’s position, the proper cost categories for the ARP - WAM project are populated correctly and the project is demonstrating reasonableness and prudence.

With the above noted, Mr. Hall explained that the Company is now planning to spend less on this project in 2018 than what was originally planned. 2 TR 289. As opposed to the Company’s original 2018 projection of \$2.2 million, the Company is now planning to spend \$1,339,926. 2 TR 289. The Company agrees to reduce its request for recovery in this case accordingly. Based on the fact that the above projects are appropriately categorized and are also reasonable and prudent, Ms. Fromm’s proposed reduction should be lowered from \$2.2 million to \$916,074.

In addition to the above, Ms. Fromm made two recommendations related to future rate case filing requirements. First, Ms. Fromm recommends that project O&M costs should be broken down into two or three subcategories. Second, Ms. Fromm recommends that the Company provide analyses showing cloud computing alternatives in IT project expense requests over \$100,000 excluding cyber security or transmission control IT projects. While the Company may ultimately be able to agree to recommendations of this nature, both of these recommendations should be rejected at this time because they are unclear.

With respect to Ms. Fromm’s first recommendation regarding breaking down O&M costs, the Company does not necessarily oppose providing breakdowns of O&M costs. However, Mr. Hall explained that Ms. Fromm’s recommendation is unclear since she does not identify the two or three subcategories of costs that would need to be presented. 2 TR 290. Mr. Hall further explained that the Company would need clarification on what subcategories are

expected to be provided in a future rate case filing before agreeing to Staff's recommendation. 2 TR 290.

With respect to Ms. Fromm's second recommendation regarding cloud computing alternatives, clarification is also needed as to what Staff intends before the Company can agree. Mr. Hall explained that similar language was agreed to in the Company's recent settlement agreement of gas rate case, Case No. U-18424. 2 TR 290. However, Ms. Fromm's recommendation does not exactly match the language agreed to in Case No. U-18424. If Staff does not intend its proposed language to match the language in the Case No. U-18424 settlement agreement, Staff has failed to provide sufficient support for implementing different language.

c. Response To The Attorney General

Attorney General witness Coppola proposed a downward adjustment to total 2018 IT capital spending in the amount of \$9.7 million (6 TR 2797-2798) and also proposed downward adjustments to the 2019 spending for the following projects: (i) the ARP Storage and Server project, in the amount of \$4.7 million; (ii) the ARP Collaborative and WAM project, in the amount of \$1.1 million; and (iii) the Field Contractor Work Management project in the amount of \$1.6 million. 6 TR 2798-2802. These recommendations should be rejected for the reasons discussed below.

Mr. Coppola's proposed reduction to total 2018 IRP capital spending is unreasonable and not supported by the record in this case. Mr. Coppola recommends a cost reduction based on a simple calculation of the difference between the 2018 IT capital spending forecast of \$43.8 million through July 2018 and the actual capital spending of \$34.1 million through July 2018. 2 TR 296. However, this simple calculation fails to take into account that the Company does not have a fixed or equal amount of IT capital spending each month. Company witness Hall explained that the Company manages IT capital spending to be commensurate with

accomplishing key business objectives. 2 TR 295. This means that the timing of IT capital spending varies throughout the year due to the nature of the ongoing IT projects and what deliverables are being met each month. 2 TR 295. Mr. Coppola's simple calculation of IT capital spending through July 2018 fails to address any of the Company's IT capital projects and therefore fails to establish that the Company is unable to spend what it has projected for 2018.

Furthermore, Mr. Hall explained that the Company is executing its IT portfolio plan and still forecasts that it will spend the total amounts projected for 2018. 2 TR 295. Mr. Hall also explained that, as of August 31, 2018, the Company's year-to-date actual IT capital spending is \$49.3 million. This compares to \$51.1 million in IT capital expenditures originally forecasted for the same period. 2 TR 295. The Company's actual spending therefore represents 96.3% of the spending that was originally forecasted. Thus, even if it were possible to do a simple calculation of year-to-date IT capital spending to determine a year-end forecast, as Mr. Coppola has proposed, the Company's IT capital spending as of the end of August 2018 demonstrates that the Company is on track to spend what it originally forecasted for 2018.

Mr. Coppola's recommended reductions to the ARP – Storage and the ARP – Server projects should also be rejected. 6 TR 2799. Mr. Coppola claims that the Company has not performed an evaluation to justify the expenditure; however, this assertion is untrue. 2 TR 291. Company witness Hall explained that the Company's records with respect to storage and server assets "indicate storage demand that is increasing 48% annually, and server demand that is increasing 16% annually." 2 TR 291. With this data, the Company's IT Department developed "a server and storage roadmap that forecasts replacements five years in advance." 2 TR 291. Mr. Hall also explained that performance and capacity reports are run on a twice monthly basis to pinpoint the exact storage and server assets that require upgrades. 2 TR 291. Furthermore,

prior to making ARP - Storage and ARP - Server purchases, the Company performs a final evaluation between the records, roadmap, and product price quote to ensure the product will meet the specific needs of the technical ecosystem it is designated for. 2 TR 291. Mr. Hall explained that this rigorous evaluation process is performed throughout the life cycle of both the ARP – Storage and the ARP – Server projects. The Company’s spending on the ARP - Storage and ARP - Server projects is neither unsupported nor premature, as Mr. Coppola suggests.

Mr. Coppola’s recommended \$1.6 million reduction to the Contractor Work Management project in 2019 is equally without merit. 6 TR 2801. Contrary to Mr. Coppola’s claims, this project is not in a conceptual stage and the forecasted expenditures are not unlikely to occur. Mr. Hall explained that the Company has thoroughly conducted the necessary research and due diligence to prove the value of the project both internally within the business and externally with the contractors. 2 TR 291-292. These research and due diligence activities included “visits to peer utilities and the solicitation of peer utility feedback through the UNITE consortium to determine the viability and potential industry best practices for contractor work management solutions.” 2 TR 292. Mr. Hall also explained the following contractor benefits of this project, which will have a corresponding benefit to the Company and its customers:

- “• Replacement of a heavily manual and paper-based solution;
- “• Standardized work management processes of gas and electric work for ease of onboarding and reduced a learning curve;
- “• Speed and efficiency gains with peer utility assistance during the restoration of customers after major outages from storms;
- “• Increased efficiencies in receiving new work and submitting completed work to the Company resulting in faster invoicing; and
- “• Reduction in contractor work rejection due to data accuracy issues.” 2 TR 292.

Moreover, Mr. Hall explained that contractors will be highly engaged, involved, and educated of the coming digital solution during the planning phase of the project in early 2019. 2 TR 292. Based on the above, Mr. Coppola's allegation that the Contractor Work Management project is conceptual and premature cannot be sustained.

Mr. Coppola's \$1.1 million cost reduction to the ARP Collaboration project in 2019 should also be rejected. 6 TR 2800. Similar to the issues discussed above, the record in this matter fails to support Mr. Coppola's criticisms. Mr. Coppola claims that the ARP Collaboration project does not appear to be mission critical but in forming that opinion he ignores evidence which demonstrates the opposite. The ARP Collaboration telephony infrastructure is extremely critical because it allows for the following:

- “• Maintaining and complying with North American Electric Reliability Corporation Reliability Standards for Transmission Operator Entity landline voice communication systems;
- “• Maintaining key telephone networks that are registered with the Department of Homeland Security's Telecommunications Restoral Program; and
- “• Supporting contact centers for residential and business customers, power plant control rooms, security, gas operations, power control, dispatch for storm restoration, gas transmission and storage, and energy distribution operations.” 2 TR 292-293.

In addition to claiming that the project is not mission critical, Mr. Coppola also tries to discredit the Company's planned spending by suggested that the Company has not experienced any problems with the telephony infrastructure in the past 12 months. This claim fails to provide support for a cost reduction. As an initial matter, the discovery response that Mr. Coppola used to form this conclusion, 20134-AG-CE-594i, provided as Exhibit AG-17, states that there have been **no system failures** with the telephony infrastructure. 2 TR 293. Mr. Hall explained that this means catastrophic events causing system-wide outages and does not mean that the

Company has not experienced **any** problems. Furthermore, Mr. Hall explained that waiting for these systems to fail, as Mr. Coppola seems to support, would be irresponsible and is not the lone indicator for system replacement. 2 TR 293. The Company's projected ARP Collaboration project for 2019 prudently addresses an aging infrastructure that is critical to the Company's operations and should therefore be approved by the Commission.

Finally, Mr. Coppola's recommended \$4.6 million reduction to projected ARP - WAM project spending for 2019 should be rejected. 6 TR 2801. Mr. Coppola claims that "the Company has not provided any evidence that replacing computers this frequently is necessary," but this is incorrect. The Company is proposing to replace personal computers on a four-year cycle because it is consistent with industry standards. 2 TR 293; see also Exhibit AG-17, page 4. Refreshing computers every four years allows the Company to: (i) avoid costs due to increasing hardware failures; (ii) avoid lost employee productivity due to downtime; (iii) reduce security risks and ensure devices are updated and patched to avoid vulnerabilities; (iv) refresh equipment for continued operating system support as older versions are required by the manufacturer; and (v) refresh equipment ensuring that employees have the required software to support their work. See Exhibit AG-17, page 4. Furthermore, the Company identified the numerous issues and risks during an evaluation of a workstation's fifth year of life. 2 TR 293-294. These issues and risks are related to decreased workstation performance and security and increased workstation repair rates. 2 TR 293-294.

The above evidence completely refutes Mr. Coppola's claim that it is unnecessary to replace computers on a four-year cycle. Contrary to Mr. Coppola's claim, the above evidence demonstrates that not adhering to a four-year refresh cycle of Company workstations leaves the Company open to increased performance and security risks. 2 TR 294. The Company's

projected ARP - WAM project spending for 2019 should be approved by the Commission because it is both reasonable and prudent.

6. Demand Response Capital Expenditures

a. Overview Of Demand Response

Company witness Hubert W. Miller III, Regulatory Reporting Manager in the Regulatory, Reporting, and Quality Section of the Company's Clean Energy Products Department, testified in support of the capital expenditures for Demand Response ("DR") programs. 5 TR 1780. DR programs are designed to be 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. The DR program helps the Company manage capacity without the need for additional supply-side electricity generation or entering into capacity contracts. 5 TR 1800. Ultimately, it is a virtual power plant to balance Michigan's electricity needs. *Id.* Consumers Energy requests approval of its capital costs for its DR programs, which are projected to be \$25,747,000 through the test year. 5 TR 1798; Exhibit A-12 (HWM-1), Schedule B-5.3, line 15. Consumers Energy has both a business DR program and a residential DR program, each of which is described separately below.

(i.) Business DR

The Company projects capital costs for the business DR program to be \$1,104,000 through the test year. 5 TR 1799; Exhibit A-12 (HWM-1), Schedule B-5.3, line 1. Mr. Miller explained how the business DR program operates. The Company works with individual business customers to set up a demand reduction plan at its facility to implement when a DR event is called, i.e., a time when electricity demand and cost are highest. Business customers contract for a specified load (kW) reduction. When Midcontinent Independent System Operator, Inc. ("MISO") expects the grid to be strained because of high electric demand or during high market

costs, the Company notifies business DR portfolio participants within 24 hours in advance of the event, informing them of when they need to reduce load. *Id.*

Participants in the business DR program receive compensation for capacity and energy reductions during events, based on their contracted capacity reduction during the program enrollment period. The capacity payment is tied to kW of reduction nominated, and the energy payment is based on kWh reduction during events, measured from an established baseline. 5 TR 1801. 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. *Id.*

If a customer fails to deliver 100% of the total nominated kW for an Emergency Event, the customer foregoes all payments if the average delivered capacity for the event is less than 70%, and the customer is assessed the real time commodity price (capped at \$1,000/MWh), as determined by the MISO Midwest Energy Market, for the kW curtailment which was underperformed per event. 5 TR 1802.

The Company entered into agreements with 127 business customers under the business DR program in 2017, resulting in a 50 MW capacity portfolio as a registered resource with MISO. The Company projects that in 2018 it will enroll 175 business customers for a total of 70 MWs registered with MISO, and in 2019 that it will enroll 300 business customers for a total of 120 MWs registered with MISO. 5 TR 1801.

Importantly, non-participating customers benefit from the Company offering a business DR program. 5 TR 1801. Because the Company's business DR program provides a flexible, repeatable, and scalable capacity resource, all customers benefit by reducing the need to

purchase additional capacity during times of peak demand, thus, reducing the cost of providing power to all customers. *Id.*

(ii.) **Residential DR**

Mr. Miller also described the Company's two Commission-approved residential DR programs: the central Air Conditioning ("AC") Peak Cycling Program and the Dynamic Peak Pricing Program. 5 TR 1802. The Company also proposes a new Bring Your Own Thermostat ("BYOT") Pilot Program. Capital costs for these programs are projected to be \$24,643,000 through the test year, and are needed to support expansion of the residential DR programs beyond the levels approved in prior cases. 5 TR 1802; Exhibit A-12 (HWM-1), Schedule B-5.3, line 8. Staff witness Naomi J. Simpson testified that Staff supports the BYOT Pilot Program. 6 TR 2565.

The residential AC Peak Cycling Program requires installation of a load control switch on the outside of a customer's home, on or near the 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, returning to normal once the cycling event ends. Participating customers receive a \$25 Visa gift card upon joining the program, and a monthly bill credit of \$7.84 during the event season of June 1st through September 30. 5 TR 1803.

Mr. Miller testified that through March 31, 2018, the Company had installed 33,773 switches or 37.825 MW at the 1.12 kW per device that was originally projected in Case No. U-18322, and that was included in the initial Smart Energy plan, and Consumers Energy saw a strong market response to its AC Peak Cycle offering with 3,554 enrollments in the first quarter of 2018 alone. 5 TR 1803. While historic performance was lower than projected, the Company was on track to meet the 42 MW target by May 2018. The Company is committed to

installing 178,000 switches by the end of 2023 to ensure AC Peak Cycling is a valuable and cost effective capacity resource.

Mr. Miller testified that, although the per customer response factor was lower than originally planned in the first year of operation,⁵ the Company continues to believe the AC Peak Cycling Program is an important customer offering. 5 TR 1804. Staff witness Simpson testified to Staff's recommendation that the Commission find that the Company met its obligation, set forth in the Commission's March 29, 2018 Order in Case No. U-18322. 6 TR 2564. She explained that the 42 MW target amount was originally calculated using an assumption of 1.12 kW of demand savings per switch installation, and therefore the 42 MW target would have correlated to approximately 37,500 switch installations. Through Staff audit, the Company has indicated that it reached 37,500 switches on May 21, 2018. *Id.*

The Company requests approval to augment its current AC Peak Cycling Program by developing and testing the use of smart thermostats under a BYOT Pilot Program. The Company would run a pilot in the summer of 2019 that would initially target 2,500 customers who have a central AC and a Wi-Fi enabled smart thermostat. The program would use 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. The projected cost of developing and implementing this pilot is \$2,209,400 and is shown on Exhibit A-106 (HWM-2), page 1, line 24, with additional detail on Exhibit A-106 (HWM-2), page 5. In the event the actual costs to administer the pilot are lower than projected, the Company would reconcile the difference in its annual DR Reconciliation proceedings. 5 TR 1805.

⁵ Consumers Energy called multiple events in 2017 to evaluate the response of its demand management system and processes. Based on the customer participation mix – e.g., fewer customers with one ton AC units participated than projected – and responses observed during the 2017 peak events, the Company is proposing to reduce the per protected customer response from 1.12 kW to 0.58 kW. 5 TR 1804.

Consumers Energy also requests approval to increase the monthly credit from \$7.84 per month to \$8.00 per month for the AC Peak Cycling Program, which will help promote the program and make it more effective in terms of marketing the program to customers. 5 TR 1805-1806.

b. Request For Approval Of Universal Peak Rewards Provision

(i.) Overview Of Universal Peak Rewards Provision

Consumers Energy currently has a Dynamic Peak Pricing Program, which is designed to encourage customers to shift their energy consumption to off-peak hours by providing less expensive rates at these times. 5 TR 1805. 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 (“CPP”) and Peak Rewards. The goals of the two pricing options are identical, but the approach to achieve them differs. The CPP option replaces the standard on-peak energy charge participants pay with a much higher critical peak energy charge. The Peak Rewards option offers customers a payment for reducing their energy usage during peak events. *Id.*

The Company requests approval to transition customers participating in its Dynamic Peak Pricing Program to a new Universal Peak Rewards (“UPR”) provision. Mr. Miller explained that customers on the proposed UPR provision would benefit year-round when they shift their energy use to less expensive off-peak hours. 5 TR 1806. Additionally, customers would receive \$0.95 per kWh as a bill credit for every kWh reduced during an event. The more energy

customers can reduce, or shift to off-peak hours, the more they can save. Customers would receive alerts via email, text, and/or phone when a peak event is scheduled. Customers would earn a bill credit if they reduce their use during the event, but would not incur any penalty if they did not reduce their use. All residential customers would be eligible to receive credits. 5 TR 1807.

An advantage of UPR is that it introduces customers to the concept that they can save money during peak events, but it does not penalize them if they choose not to reduce consumption during a peak event. Mr. Miller explained:

“The Company views the UPR provision as a way to introduce customers to the Company’s demand response programs and to get them comfortable with the idea of participating in peak events in a ‘no regrets’ way. . . . As mentioned in my direct testimony, the UPR provision is based on a similar successful residential demand response program provided by Baltimore Gas and Electric (‘BG&E’). Since beginning their program, BG&E has enabled 330 MW of demand response over a three-year period and has seen an average participation rate of 74%, indicating that customers do respond to positive incentives (rewards).” 5 TR 1828.

To implement UPR, the Company would need to reconfigure communication and billing systems, and conduct systems testing. 5 TR 1807. As such, the Company proposes to upgrade its systems in 2019, and to begin transitioning customers in 2020, with full enrollment by the summer of 2021. A phase-in enrollment approach would reduce the risk of operational setbacks by incorporating learnings gained through implementation and customer feedback. Customers could opt-out of receiving notices of DR events, but would remain eligible for credits if they reduced usage. 5 TR 1807. The cost of implementing UPR is primarily related to system upgrades and is projected to be approximately \$10 million of capital expense for the test year.

Id.

Residential customers would be able to participate in AC Peak Cycling concurrently with UPR starting in the summer months of 2020. However, the Company would only compensate a customer who chooses to participate in both options with the greater credit that each option would produce in any single month. Upon completion of each billing cycle, the credit for each program will be determined and compared against one another. The larger credit will be applied to the customer's invoice for that month. 5 TR 1627.

(ii.) **Response To Staff's Position On UPR Provision**

Staff witness David W. Isakson testified that Staff did not support the Company's proposed UPR provision, and instead proposed that the Commission adopt his proposed CPP. 6 TR 2354-2365. As discussed below, the Company does not oppose the implementation of CPP in addition to UPR, and while Mr. Isakson raised issues in connection with UPR, none of them provide any basis to deny UPR.

Mr. Isakson testified that Staff prefers CPP over UPR because UPR is susceptible to free-ridership and does not penalize customers who choose to not change their behavior during the event. 6 TR 2361. The potential for free-ridership, however, is not sufficient reason for the Commission to not approve UPR. Mr. Miller explained:

"I agree that there will be random situations in which some customers happen to be away from their homes on an event day, and that they have also decided to increase the temperature in their home for some reason other than the prompt that it is an event day. While I do not dispute the potential existence of some free-riders, I do disagree with the notion that it is a systemic issue that warrants disapproval of the Company's proposal. Indeed, the purpose of calling an event is that customer demand on the system is too high. In other words, the problem is not that too many customers are using less air conditioning as they leave their house during an event day. However, I would anticipate that increased load during event days would generally offset the potential of free-ridership. In addition, Mr. Isakson suggests that the Critical Peak Pricing provision he is proposing is not susceptible to free ridership. However, it seems equally as likely that some customers

participating in the CPP will benefit from receiving the lower off-peak rates during the month and randomly avoiding the higher CPP during an event day just because they were not home.” 5 TR 1827-1828.

Thus, the possibility that a customer may occasionally receive a credit without specifically intending to respond to a peak event is not a basis to deny UPR. If UPR results in the reduction of electric consumption during peak periods, even if coincidentally in some cases, then it will have met its goal.

Mr. Miller discussed studies that evaluated the difference between an opt-out and opt-in DR program, observing that the studies support the effectiveness of a DR program like UPR. In November 2016, the US Department of Energy’s Smart Grid Investment Grant Program published its final report, admitted as Exhibit A-162 (HWM-5), which found that the average opt-out recruitment approach successfully enrolled approximately 6.2 times more participants than the average opt-in approach (93% vs 15%). While peak demand reductions were generally lower per customer for the opt-out approach, the aggregate demand reduction was much higher given the larger number of customers participating. Further, the overall cost-benefit advantages are greater for opt-out approaches than opt-in approaches, since efforts to default customers on rates requires less effort than enrolling volunteers. The study found that the benefit-cost ratio was greater than 2.0 for opt-out and between 0.7 and 2.0 for opt-in, depending on rate and technology combination.

Additionally, through Consumers Energy’s discussions with Baltimore Gas & Electric (“BG&E”), the Company learned that BG&E experienced lower costs for its similar Smart Energy Rewards awareness campaigns when compared to the cost of multiple touchpoints required to get customers to take action to opt-in. The US Department of Energy’s study supports BG&E’s experience in finding that while customer engagement, marketing, and

outreach efforts are essential for success under both approaches, “[s]uccessful opt-in enrollments require extensive marketing and outreach to sufficiently raise customer awareness and successfully encourage participation in time-based rates. On the other hand, opt-out recruitment approaches do not require nearly the same level of market research to achieve high enrollment levels.” Exhibit A-162 (HWM-5), page 40.

Mr. Isakson also asserted that UPR would not comply with § 95(1) of 2016 PA 342, MCL 460.1095(1), because it would not be voluntary. 6 TR 2364. The Commission should not adopt Staff’s position. Mr. Isakson emphasized the statement in MCL 460.1095(1)(a) that “[e]lectric provider participation and customer enrollment in such programs are voluntary.” UPR would not violate this provision. Consumers Energy would not require customers to enroll in a separate rate or program. In fact, as discussed above, UPR does not require customers to do anything. Customers would merely receive notices of opportunities to receive bill credits. Customers would be free to ignore such notifications, and can choose not to receive them at all. Customers would not incur any penalty for not reducing usage during a peak event, and, as discussed above, in some cases might receive billing credits if their consumption only coincidentally decreased during a peak event.

Contrary to Mr. Isakson’s claim, the Company’s UPR is not “opaque and imprecise.”

6 TR 2361. Mr. Miller explained:

“Q. On [6 TR 2362-2364], Mr. Isakson explains why he believes the UPR is opaque in its calculation. Does the Company agree with his conclusion?”

“A. No, the Company does not agree with this conclusion. Specifically, Mr. Isakson suggests that the process of estimating the customer’s baseline and subsequent bill credits after the critical event is confusing to customers because they will not know the starting point at which they are measured. The Company believes that to encourage

UPR customers to save during critical events, it is not necessary for customers to know their specific kWh baseline. As with other price-based demand response programs, a critical event signals to UPR customers that it is temporarily more expensive to consume electricity. Like the CPP provision, UPR raises the opportunity cost of consuming electricity during critical events. For both provisions, the key element customers need to know is that the cost (whether actual cost or opportunity cost) is higher during critical events, and that they can save on their bills by reducing consumption below normal during those times.

“Q. On [6 TR 2362-2364], Mr. Isakson explains why he believes the UPR is imprecise in its calculation. Does the Company agree with his conclusion?

“A. The Company recognizes that customer baseline calculations are not perfect. To address this, the Company is working with Cadmus, a third party evaluation company, to test the accuracy of multiple baseline calculation methods in 2019 to determine the most precise method before implementing the UPR provision in 2020. Cadmus will work with recognized industry experts at The Brattle Group (‘Brattle Group’) to provide technical support during the testing and baseline analysis. In addition, given the complexity and concerns raised by Mr. Isakson, the Company would appreciate collaborating with Staff, and other interested stakeholders in this proceeding, to align on a robust method for establishing customer baselines.

“Q. Please explain the Company’s intended approach for evaluating the accuracy of the customer baselines.

“A. Cadmus and Brattle Group will test the predictive accuracy of candidate baseline calculation methods using 2018 critical events data as a proxy for future program implementation. Candidate methods will be those expected to predict customer baselines most accurately based on a review of calculation methods used for similar programs by other utilities, and will include a variety of day-matching and regression baseline calculation methods. Cadmus will collect AMI interval consumption data for a large sample of customers that are currently not participating in a demand response program. Cadmus will calculate the prediction error (difference between the estimated interval consumption calculated with the baseline calculation

method and the interval metered consumption) for sampled customers during demand response event hours in 2018. Finally, Cadmus will assess the accuracy of the calculated baseline using statistical analyses that measure accuracy including the relative root mean squared error, mean absolute percentage error, and median percentage error to identify a customer baseline calculation method that is precise, transparent, replicable, and easy for customers and stakeholders to understand.” 5 TR 1830-1832.

Thus, UPR is not “opaque and imprecise.” Customers will understand that reducing consumption during peak events will save them money, and Consumers Energy has already begun working with Cadmus to refine the process to calculate such reductions and award credits to customers.

c. Conclusion

The Commission should approve the Company’s DR capital expenditures. No party witness opposed these capital expenditures. While Staff witness Isakson proposed that the Commission adopt this proposed CPP, rather than the Company’s proposed UPR provision, Staff did not propose any reduction to capital expenditures. Rather, Ms. Simpson specifically testified that Staff did not recommend any adjustments to Consumers Energy’s C&I DR expenditures (6 TR 2563) or residential DR expenditures (6 TR 2568).

For the reasons provided above, the Commission should approve the UPR provision. Additionally, as no party witness opposed the Company’s BYOT Pilot Program (and Staff supported it), and no party opposed the AC Peak Cycling Program credit increase for \$7.84 to \$8.00, the Commission should approve them.

7. Accumulated Provision For Depreciation

The depreciation reserve balance for the projected test year was developed by applying depreciation rates to the average of plant-in-service as of December 2018 and December 2019. 2 TR 330. The originally filed accumulated provision for depreciation for the projected test year

was \$5,862,598,000. Exhibit A-12 (HJM-45), Schedule B-3, line 8, column (c). Exhibit A-12 (HJM-42), Schedule B-1, line 2, column (d), indicated a jurisdictional adjusted depreciation reserve amount of \$5,838,853,000.

Staff witness Stacy A. Harris provided Staff's projected test year accumulated provision for depreciation in the non-jurisdictional (total Company) amount of \$5,859,092,000. 6 TR 2461. Staff's jurisdictional projected test year accumulated provision for depreciation was \$5,835,069,000. Exhibit S-2, Schedule B-1, line 2, column (f). The difference between the Company's initially filed projected test year accumulated provision for depreciation amount and Staff's proposed amount was the result of adjustments by Staff to the Company's projected capital expenditures.

In rebuttal, Company witness Myers included adjustments to the Company's originally filed revenue deficiency. 2 TR 353. These adjustments were explained by Ms. Myers as follows:

"The Company made the following adjustments to its originally filed revenue deficiency:

"1. A reduction in plant in service of \$4,252,000, a \$311,000 decrease in depreciation reserve, a \$512,000 decrease in depreciation expense, and a \$47,000 decrease in property tax expense to reflect capital spending reductions for four information technology projects; ARP-Storage, Legal Archiving Tool, Customer Experience Improvements, and ARP – WAM. (Exhibit A-165 (HJM-68)). Company witness Josh R. Hall discusses this in his rebuttal testimony;

"2. A reduction in plant in service of \$2,872,000, a \$88,000 decrease in depreciation reserve, a \$88,000 decrease in depreciation expense, and a \$32,000 decrease in property tax expense to reflect capital spending reductions for HVD – New Business. (Exhibit A-165 (HJM-68)). Company witness James R. Anderson discusses this in his rebuttal testimony;

“3. A decrease in O&M expense of \$2,235,000 for marketing expense. (Exhibit A-167 (HJM-70). Company witness Hubert W. Miller discusses this in his rebuttal testimony.

“4. A net increase in revenue of \$2,546,000 to reflect the impacts of the Case No. U-18322 Errata Order, Rehearing Order, and the update of street lighting billing determinants. (Exhibit A-167 (HJM-70). Company witness Eugène M.J.A. Breuring discusses this in his rebuttal testimony.

“5. A decrease in the cost rate for long-term debt and short-term debt included in the calculation of the cost of capital. Company witness Andrew J. Denato discusses this in his rebuttal testimony.

“6. A reduction in plant in service of \$26,839,000, a \$1,283,000 decrease in depreciation reserve, a \$1,593,000 decrease in depreciation expense, and a \$299,000 decrease in property tax expense to reflect capital spending reductions for contingency. (Exhibit A-165 (HJM-68)). For purposes of this rate case, the Company is no longer pursuing recovery of this item.” 2 TR 353-354.

These adjustments resulted in a total adjusted accumulated provision for depreciation for the projected test year of \$5,837,490,000. Exhibit A-165 (HJM-68), line 11, column (e). The jurisdictional adjusted depreciation reserve amount is \$5,837,490,000. Appendix B, page 1, line 5, column (e).

B. Working Capital

1. Working Capital Methodology And Calculation

Rate case working capital is developed using the balance sheet methodology. 2 TR 332. Use of the balance sheet methodology was mandated by the Commission in Case No. U-7350, June 11, 1985 Opinion and Order, and in Case No. U-15895, December 23, 2008 Order, filing requirements. 2 TR 332. The Company requests that working capital be set at a jurisdictional amount of \$800,206,000 for purposes of determining rate base in this case. See Exhibit A-164

(HJM-67); Appendix B, page 1, line 8, column (e). The Company's projection is reasonable and consistent with the approach typically used in determining test year working capital using the balance sheet methodology.

Company witness Myers testified that the Company, in its initial filing, developed its projected test year working capital requirement using the 2017 historical working capital as its starting point. 2 TR 332. This was first updated to reflect the 13-month average ending February 2018 actual balances, and then the February average balances were adjusted to reflect: (i) changes to pension and OPEB balances based on projections sponsored by Company witness Lora B. Christopher; and (ii) accrued tax. 2 TR 332. Details of these updates are shown in Exhibit A-12 (HJM-46), Schedule B-4, pages 1 and 2.

2. Response To The Attorney General

The Attorney General proposed reducing the level of working capital in this case by \$49,900,000 to \$754,100,000 to reflect: (i) a lower cash balance level, and (ii) a lower level of accounts receivable and accrued revenues. 6 TR 2826. These changes are calculated and shown in Exhibit AG-25. These adjustments are unreasonable.

First, Attorney General witness Coppola indicates that accounts receivable and accrued revenues should be lower as a result of reductions in rates related to the Electric Tax Credit A, Case No. U-20102. 2 TR 349. This action is inappropriate. The accounts receivable and accrued revenue for rate reductions should not be adjusted related to the Electric Tax Credit A, Case No. U-20102, because the tax credit will be discontinued when rates are set in this case. The purpose of the Electric Tax Credit A was to provide an offset to the base rates set in Case No. U-18322 so that the rates would include the current tax expense at a 21% federal income tax rate. 2 TR 350. However, this tax rate is already reflected in this case. Therefore, the test year

rates would not be reduced by the Electric Tax Credit A and will reflect the rate relief provided for in this case. In making his recommended adjustment, Attorney General witness Coppola failed to acknowledge that the Electric Tax Credit A will not be in effect during the test year.

Additionally, Attorney General witness Coppola recommended that the Commission reduce the Company's forecasted working capital amount for the test year by \$36.3 million to reflect a lower cash balance than shown in the Company's filing. 6 TR 2826. Attorney General witness Coppola argues that holding a cash balance equal to approximately 2% of Company revenues, as Consumers Energy has proposed, is not "appropriate or advisable." 6 TR 2826. Mr. Coppola claims that the Company has multiple bank lines of credit and access to the commercial paper market, which it can use to fund operations. 6 TR 2827. Company witness Andrew J. Denato testified on rebuttal that, contrary to Mr. Coppola's claim, the higher cash balance is needed. Mr. Denato testified:

"There are a number of legitimate business reasons that support the level of cash presented by the Company in the case:

- "• Given the seasonality in cash flows (higher during spring and summer as the winter gas bills are collected, and lower in the fall as gas is injected into storage fields), there are certain months the Company will have large cash balances (mainly in spring and summer) which increases the Company's average cash balance for the year;
- "• In order to obtain an attractive interest rate for long-term bond financing and to minimize the refinancing risk, the Company at times issues new bonds a few months in advance of the actual maturity, which gives rise to a higher average cash balance. The timing for the issuance of long-term debt is influenced by several factors, including blackout dates (i.e. dates when the Company is in the middle of finalizing its quarterly earnings and cannot access public markets), stability of capital markets, and the expected movement in interest rates; and
- "• Lastly, given the Company's large capital expenditure program, the Company aims to maintain an overall

liquidity that is sufficient to carry out not only the day-to-day operations but also have the flexibility to meet investing activities should there be a delay in accessing long-term capital from capital markets.” 4 TR 876-877.

Mr. Denato testified further that the Commission has already rejected a virtually identical proposal by Mr. Coppola in Case Nos. U-17990 and U-18124, finding that the Company’s proposed cash balance was “reasonable and prudent.” 4 TR 877. Mr. Denato testified that the Company’s projected cash balance included in Working Capital for the test year “is needed, reasonable, and comparable to other utilities.” 4 TR 877. Therefore, the Attorney General’s proposed reductions to Working Capital should be rejected.

C. Total Rate Base

Consumers Energy requests the Commission set rates using a jurisdictional total rate base for the projected test year of \$10,638,735,000. Appendix B, page 1, line 9, column (e); Exhibit A-164 (HJM-67). The primary components (in thousands of dollars) are:

Total Utility Plant	\$ 15,734,226
Less: Accumulated Depreciation	<u>(5,837,490)</u>
Net Utility Plant	\$ 9,896,736
Less: Retainers & Customer Advances	(58,207)
Working Capital	<u>800,206</u>
Total Rate Base	\$ 10,638,735

A more detailed calculation of rate base is shown in Appendix B to this Initial Brief.

IV. RATE OF RETURN AND CAPITAL STRUCTURE

A. Introduction And Identification Of Areas Of Disagreement Between The Company And Staff

The rate of return used to set rates for a regulated utility is based on the weighted average costs of the sources of capital comprising the capital structure. The weighted cost for each component of the capital structure is determined by multiplying the percentage ratio for that

component by the cost rate for that component. The weighted cost rates for each component are then added to determine the overall rate of return.

Consumers Energy requests the Commission establish rates in this case using an after-tax overall rate of return of 6.28%, calculated as set forth in Exhibit A-147 (AJD-12).⁶ For the convenience of the Commission, the capital structure and rate of return summary from Exhibit A-147 (AJD-12), are reproduced on page 1 of Appendix F to this Initial Brief.

Consumers Energy is requesting that the authorized ROE be set at 10.75%. This is 75 basis points higher than the rate of return authorized by the Commission for Consumers Energy in the Company's most recent electric rate case, Case No. U-18322. 3 TR 469. For reasons set forth in the direct and rebuttal testimony of Consumers Energy witness Srikanth Maddipati (see 3 TR 411-470, 476-535) and as discussed below, Consumers Energy requests the ALJ recommend, and the Commission find, that adopting Consumers Energy's proposed authorized ROE of 10.75% in this case is reasonable given the risk profile for Consumers Energy's electric business, current conditions, and expectations regarding future increases in federal treasury rates.

In developing its recommended capital structure and cost rates, Staff reviewed the capital structure and cost rates proposed by Consumers Energy in its initial filing and recommended adjustments be made to the common equity balance, short-term debt cost, and the ROE (see Exhibit S-4, Schedule D-1). The Company accepts Staff's projection cost of long-term debt because Staff used the latest projections for the 30-year United States Treasury rate and added a spread of 100 basis points, also from the spread on the Company's May 2018 bond issuance and,

⁶ This after-tax overall rate of return was updated in Mr. Denato's rebuttal testimony and exhibits. The original after-tax overall rate of return requested by the Company was 6.33% (see Exhibit A-14(AJD-1), Schedule D-1; Appendix F, page 2).

thus, it is based on the most recent issuance. 4 TR 859. Consumers Energy does not agree with Staff's recommended common equity balance of \$7,240,345,774, short term debt cost rate of 3.35%, and reduction in the Company's ROE to 9.75%. Record evidence supports the Company's common equity balance instead of Staff's common equity balance, as Staff's common equity balance fails to recognize both the significant capital investments necessary to maintain and improve the Company's utility infrastructure and, further, fails to take into account the effects of the Tax Cuts and Jobs Act of 2017 ("TCJA") and necessary equity infusions in 2019. Additionally, record evidence supports the Company's short-term debt cost rate as Staff's projected short-term debt – renewable liability balance fails to take into account the cost assigned to that balance. Finally, the record evidence supports finding that a return of 9.75% would substantially understate the appropriate ROE for Consumers Energy's electric business and would be unreasonable and unlawful.

The difference between the Company's calculated overall rate of return of 6.33%, as set forth in Mr. Denato's direct testimony and exhibits, and Staff's calculated overall rate of return of 5.81% is attributable to the disagreement concerning the Company's common equity balance and short-term debt cost rate. Consumers Energy requests the Commission find that it is reasonable to adopt an authorized ROE at 10.75%, as proposed by the Company, and the Company's other proposed cost rates and debt and equity balances, as shown on page 1 of Appendix F, rather than the capital structure and cost rates recommended by Staff.

B. Test Year Capital Structure

In the current case, Consumers Energy proposed that the overall rate of return of 6.28%, as updated in Mr. Denato's rebuttal testimony and exhibits, on an after-tax basis, should be calculated using a projected Consumers Energy capital structure for the 12-month period ending

December 31, 2019. 4 TR 811; Exhibit A-147 (AJD-12), column (f), line 12. The cost of the components and weighted cost are shown in Exhibit A-147 (AJD-12), columns (e) through (h).

As shown in Exhibit A-147 (AJD-12), and Exhibit S-4, Schedule D-1, Company and Staff witnesses were in agreement as to the amounts outstanding that should be used in the capital structure for long-term debt, short-term debt, preferred stock, deferred federal income taxes, and the Job Development Investment Tax Credit (“JDITC”). The capital structure, as supported by Company witness Denato, is reproduced in Appendix F, page 1. Consumers Energy requests the Commission find this represents a reasonable and appropriate capital structure to use in this case and adopt this capital structure.

1. Capital Structure Component Balances

a. Common Equity Balance

In calculating the 13-month average common equity balance for the test year, Mr. Denato began with the common equity balance as of December 31, 2017, as shown in Exhibit A-14 (AJD-2), Schedule D-1a, page 1, column (e-6), and then made adjustments as shown in column (f-6). 4 TR 812. The common equity adjustment consisted of an adjustment to reflect retained earnings from January 2018 through December 2019, and an adjustment to reflect the average of equity infusions in 2018 and 2019. 4 TR 812-813. The calculations are shown in Exhibit A-14 (AJD-2), Schedule D-1a, page 1. The resulting average common equity balance for the test year is \$7.438 billion resulting in an equity ratio of 52.5%. Exhibit A-14 (AJD-2), Schedule D-1a.

The Commission’s final orders in the Company’s recent electric and gas rate cases (Case Nos. U-17990 and U-18124), indicated the Commission’s desire to see a “rebalancing” of the Company’s equity ratio from the levels utilized in recent years. In the Company’s most recent

electric rate case, Case No. U-18322, Consumers Energy demonstrated its commitment to this rebalancing by accelerating its efforts to formalize and implement a strategy for rebalancing its equity ratio. In that case, the Company requested an equity ratio which was 46 basis points lower than that approved in Case No. U-18124. The Commission recognized these efforts and, in its March 29, 2018 Order in Case No. U-18322, the Commission found that Consumers was on track to rebalance its capital structure over the five-year timeframe the Commission set out in the February 28, 2017 Order, and agreed with the Company's proposed equity ratio.

In the midst of these Commission orders, the TCJA was signed into law in December 2017, with an effective date of January 2018. As Mr. Denato explains in his testimony, the TCJA brought sweeping changes to the federal tax system and has significant impacts on United States utilities. 4 TR 816. As Mr. Denato indicated in his direct testimony, TCJA will: (i) reduce electric utility base rates and reduce gas utility rate base and IRM rates; and (ii) will necessitate a one-time reduction to the Company's total deferred tax balances. 4 TR 816-817. While these savings will be passed on directly to the Company's customers, they reduce future cash inflows to the Company and reduce credit quality. 4 TR 817. Hence, while Consumers Energy continues to actively engage in a course of action calculated to rebalance its equity ratio, the glide path pace of attaining an equity ratio of 50% by 2023 is no longer reasonable based on the new economics that the Company is facing as a result of the TCJA. 4 TR 819.

Against the backdrop of the Commission's objectives and the intervening effect of the TCJA, Company witness Denato recommends reducing the 2017 actual equity ratio of 53.6% to 52.5%, despite the fact that negative credit impacts of federal income tax would support a higher equity ratio. 4 TR 819. The Company does so, as Mr. Denato explains, because "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 our filed position of 52.5%.” 4 TR 819. Mr. Denato further explains why the 52.5% equity ratio requested in this case is the right balance for customers and the Company as follows:

“...Consumers Energy is in the midst of a major infrastructure upgrade cycle throughout our service territory in Michigan. We will require billions of dollars in new capital funding to complete these needed upgrades for our customers. Our goal is to raise the necessary capital at the lowest overall cost to customers over the long term. While it may look attractive in the near term to take a severe reduction in the equity layer of the Company, such a move and the resulting credit downgrade could lead to our customers paying higher financing costs over the long term. Given the negative credit impacts of federal tax reform on utilities, it is of great importance for the regulatory response to be balanced and thoughtful. Lastly, it is important to note that the Company is intending to strike this delicate balance and commitment to our customers by decreasing its equity ratio from 53.6% at the end of 2017 to 52.50% for the test period in this case.” 4 TR 820.

As the evidence in this case demonstrates, the Company has provided a thorough analysis explaining why its proposed equity ratio is reasonable and prudent (resulting in a reduction to the equity ratio while adjusting the glide path to rebalancing arising out of the effects of the TCJA). Further, the reactions of rating agencies (see Exhibit A-149 (AJD-14)) and other regulators, along with the Company’s quantitative analysis, highlight and identify the negative credit implications of the TCJA. Thus, based on the evidence presented in this case, the Commission should adopt the Company’s equity balance for the test year ending December 31, 2019 of \$7.438 billion and equity ratio of 52.5%. Exhibit A-147 (AJD-12) (see also Exhibit A-14 (AJD-2), schedule D-1a, pages 1 and 3).

b. Long-Term Debt Balance

In determining the test year long-term debt, Mr. Denato began with the December 31, 2017 long-term debt balance and adjusted the balance for projected debt retirements and

issuances. 4 TR 820-822. Mr. Denato projected an average long-term debt balance for the test year of \$6.693 billion. Exhibit A-147 (AJD-12); Exhibit A-14 (AJD-1), Schedule D-1; Exhibit A-14 (AJD-2), Schedule D-1a, page 1. The calculation is shown in Exhibit A-14 (AJD-2), Schedule D-1a, page 2. This amount is the same amount recommended by Staff. Exhibit S-4, Schedule D-1.

c. Short-Term Debt Balance

Mr. Denato projected an average short-term debt balance for the test year of \$154 million. This balance is shown on line 5 of Exhibit A-147 (AJD-12), in column (b), and on line 10 of Exhibit A-14 (AJD-2), Schedule D-1a, page 1. Mr. Denato stated that the average short-term debt balance is composed of two components: (i) average short-term debt – revolver/commercial paper balance of \$113 million; and (ii) the average short-term debt – Renewable Liability balance of \$41 million. 4 TR 822. The short-term debt balance recommended by Staff is the same as recommended by the Company. Exhibit S-4, Schedule D1.

d. Deferred Federal Income Tax Balance

Mr. Denato proposed an increase in the Company’s deferred tax balance of \$180 million over the December 31, 2017 levels based on internal Company projections from the Company’s Tax Department of book versus tax differences expected through December 2019. 4 TR 830. This resulted in a deferred tax balance for the test year of \$3.322 billion. Exhibit A-147 (AJD-147), line 6, column (b); Exhibit A-14 (AJD-1), Schedule D-1, line 12, column (b); Exhibit A-14 (AJD-2), Schedule D-1a, line 126, column (g). This amount is the same as recommended by Staff. Exhibit S-4, Schedule D-1.

e. Other Capital Structure Balances

The Company and Staff used balances for preferred stock corresponding to balances in the historical period. Exhibit A-14 (AJD-2), Schedule D-1a, line 4; Exhibit S-4, Schedule D-1, line 2. For the test year JDITC balance, Mr. Denato testified that the Company estimates the December 31, 2019 balance will be \$107 million based on internal projections from the Company's Tax Department through December 2019, with components for JDITC based upon the allocation of long-term debt, preferred stock, and common equity. 4 TR 831; Exhibit A-14 (AJD-2), Schedule D-1a, line 19, column (g). This is the same amount recommended by Staff. Exhibit S-4, Schedule D-1.

2. Staff's, The Attorney General's, The Association Of Businesses Advocating Tariff Equity's, And Residential Customer Group's Proposals To Adjust The Common Equity Balance And Equity Ratio Should Be Rejected By The Commission

a. Response To Staff

As discussed above, the Company has calculated the average common equity balance for the test year as \$7.438 billion resulting in an equity ratio of 52.5%. Exhibit A-14 (AJD-2), Schedule D-1a. Staff proposed to adjust the common equity balance downward to \$7.240 billion. Exhibit S-4, Schedule D-1. While Staff started with the Company's actual common equity balance December through June 2018, and followed the Company's preferred method for estimating retained earnings, Staff did not recognize the Company's planned equity infusions. 6 TR 2497. As explained by Staff witness Kirk D. Megginson, Staff recognized the entire January and June 2018 equity infusions into the Company's equity balance forecast, but modified the January and June 2019 infusions by lowering the January 2019 infusions from \$300 million to \$200 million, and the June 2019 infusions from \$350 million to \$100 million. 6 TR 2497. Staff's rationale for those adjustments was based only on historical infusions. 6 TR

2497-2498. Staff, thus, recommended 2019 equity infusions “mirror the 2018 actual equity infusions the Company received.” 6 TR 2498. Staff witness Megginson completed his analysis by saying that: “Staff’s 51.8% common equity balance supports the Commission’s objective of a more balanced capital structure that is less costly to ratepayers and still reasonable for the company to maintain its credit and access to capital markets.” 6 TR 2498. As discussed below, this analysis falls short in that it provides no facts, support or quantitative evidence to justify the \$350 million adjustment to equity infusions, and wholly disregards the effect of the TCJA on 2019 equity infusions, debt issuances, and overall equity ratio of the Company.

As Mr. Denato testified, the Company’s projected equity balance for the test year in this case takes into account equity infusions from CMS Energy that are planned, needed, and consistent with the expected capital needs of Consumers Energy through the test year ending December 2019. 4 TR 849. As noted by Mr. Denato in his rebuttal testimony, Staff cites to historical infusions as its sole basis for its adjustment to the equity balance and fails to demonstrate any errors or other deficiencies in the adjustments made by the Company to reach its common equity balance. As he further notes, “[s]imply ‘mirroring’ 2018 actual equity infusions by the Company is not a meaningful analysis of projected changes in actual capital structure balances.” 4 TR 849. In fact, Mr. Denato’s analysis of the Company’s capital structure, which goes well beyond “mirroring” 2018, demonstrates that the projected changes are consistent with the Company’s capital requirements. Staff witness Megginson’s failure to consider the Company’s significant capital investments to maintain and improve its infrastructure causes the Company’s equity balance to be inaccurate and understated. 4 TR 850.

Similarly, Staff’s oversight of a discussion, or other analysis of the effects of the TCJA on 2019 equity infusions and debt issuances, which create a significant increase in the level of

long-term debt financing compared to previous years, was also in error and created an artificially lower equity ratio. 4 TR 851. As Mr. Denato pointed out in his rebuttal testimony, when using the Company's projected equity infusions, Staff's projected common equity balance for the test year ending December 2019 is increased from 7,240,345,774 to \$7,437,782,385, the same balance and resulting common equity ratio as proposed in Mr. Denato's testimony. 4 TR 859.

Although Staff supports a 51.8% equity ratio, it appears to only do so in an effort to narrowly construe the Commission's previously-discussed objective of balancing capital structure. Staff, however, overlooks that when the Commission initially discussed a glide path to balancing capital structure, it did so prior to the enactment of the TCJA and left room for the Company to justify a modification of that glide path. As discussed by Company witness Denato, the negative cash flow impacts of the TCJA have been recognized by credit rating agencies such as Standard and Poor's ("S&P") *Global Market Intelligence* ("S&P Global"), Moody's Investor Service ("Moody's), and Fitch Ratings. 4 TR 853. Staff has failed to consider the significance of these impacts on the appropriate equity ratio in this case, and this renders its analysis of the appropriate equity ratio deficient. Mr. Denato, however, discussed the impacts of the TCJA in detail in his rebuttal testimony. See 4 TR 852-859. Since this is the only supported evidence on the record, Mr. Denato's proposed common equity balance and equity ratio should be accepted by the Commission.

b. Response To The Attorney General

Attorney General witness Coppola argued that the Commission should adjust Consumers Energy's common equity balance downward in order to artificially adjust the Company's equity ratio below the Company's forecasted 52.50%. In order to achieve his adjustment, the Attorney General recommended that the Commission adjust the Company's common equity balance downward by \$354 million, while simultaneously adjusting the Company's long-term debt

balance upward by \$354 million. 6 TR 2829. This results in a capital structure with 50% of common equity and 50% of debt and preferred stock. 6 TR 2829. The result is a common equity ratio of approximately 50.0%. 6 TR 2831; Exhibit AG-26.

In support of this proposed common equity ratio, the Attorney General argues that three factors need to be considered including: (i) the Commission's directive in the Company's electric rate case, Case No. U-17990 that moving to a 50/50 capital structure is appropriate in the absence of evidence suggesting otherwise; (ii) the Company's practice of funding a significant part of its equity contributions with funds from long-term debt issued at the parent company level; and (iii) the fact that the common equity ratio of the peer group, used to access the cost of common equity in this case, averages slightly below 49%. 6 TR 2830. As discussed below, these arguments are without merit and should be rejected.

First, in rebuttal testimony, Company witness Denato pointed out that, contrary to Mr. Coppola's proposal, the Commission's directive from Case No. U-17990 did not require an immediate reduction to a 50% equity ratio. 4 TR 870. Instead, the Commission's Order specified that it expects that Consumers Energy "will have arrived at . . . a balanced structure within the five-year infrastructure plan time period" or that Consumers Energy will "present a strategy to return to . . . a balanced structure within the five-year infrastructure plan time period". February 28, 2017 Order, page 64 (emphasis added). Even that directive was not absolute. The Commission's February 28, 2017 Order also provided Consumers Energy the option to provide a more detailed analysis explaining why the Company would not reasonably or prudently be able to meet rebalancing of the equity ratio within the five-year time period contemplated by the Commission. *Id.* Although the Commission did express concerns in Case No. U-17990 about the relatively higher cost the equity capital represents in the capital structure, the Commission

also expressed its understanding of a couple of important countervailing considerations that explain why it might be ill-advised to take immediate action to artificially reset the Company's capital structure. The Commission acknowledged that "a company with more debt is a financially riskier enterprise" than one with less debt, and that the Commission "understands the importance of access to capital, particularly in times of heavy infrastructure investment cycles." *Id.* at 63.

Based on these legitimate countervailing concerns, the Commission chose not to recklessly charge forward with an artificial reset of the Company's common equity ratio in Case No. U-17990. Instead, the Commission took the measured approach of directing the Company toward three options⁷ and establishing a reasonable timeframe, based on a sound understanding of the Company's investment needs over the next several years, for accomplishing one of those options. Here, the Company put together a case that presents quantitative evidence and rationale in support why the Company cannot reasonably or prudently rebalance its equity ratio within the five-year period contemplated by the Commission; specifically, the passing and implementation of the TCJA and the effects of the TCJA on the Company's equity ratio and financial health of the Company. Thus, at this time, Mr. Denato has testified about several considerations that explain why the Company's equity balance will need to be slightly higher than 50% over the next five years. In responding to Mr. Coppola's proposal, Mr. Denato summarized these in his rebuttal testimony:

⁷ The Commission in Case No. U-17990 offered Consumers Energy three options: (Option 1) arrive at a rebalanced equity ratio within the five-year infrastructure plan; (Option 2) present a strategy for rebalancing its equity ratio within the five-year infrastructure plan; or (Option 3) provide a more complete analysis explaining why it is reasonable and prudent to continue maintaining an equity ratio consistent with its recent rate case outcomes (around 53%). Although the Commission's five-year timeline for achieving Options 1 or 2 remains far off, the Company already made additional efforts in its initial filing to include the more detailed analysis called for in Option 3. See generally 4 TR 812-820; Exhibit A-82 (AJD-10).

- “• The Company is making significant capital investments over the next five years to maintain and improve utility infrastructure. The projected equity ratio enables the Company to maintain strong credit ratings and better withstand any shocks in the financial markets, thereby ensuring a smooth implementation of its capital expenditure program. This also enables the Company to prefund its debt maturities to take advantage of low interest rates without jeopardizing the financial ratios.;
- “• Certain credit rating agencies include securitization debt when calculating debt to equity ratios and also consider items such as Power Purchase Agreements (‘PPAs’), benefit obligations, and leases as “debt” when calculating debt to equity ratios. These rating agency adjustments are financially sound and necessary to reflect the impact of the long-term fixed payment obligations that PPAs require the purchaser to pay. Basically, PPAs are debt-like in nature; and
- “• After considering Standard and Poor’s (‘S&P’) adjustments to debt, the Company’s equity ratio is 210 basis points lower than peers, reflecting the relatively higher amount of debt assigned to Consumers Energy by S&P. This is reflected on page 2 of my Exhibit A-82 (AJD-10) included in my direct testimony. A slightly higher common equity ratio enables the Company to maintain reasonable ratios after considering such adjustments.”
4 TR 851-852.

Additionally, “federal tax reform legislation passed in December 2017, and effective beginning in January 2018, lend further justification to the 52.50% equity ratio proposed in this case and make the equity ratio approved in this case critical to the financial health of the Company.”
4 TR 870. Thus, “Mr. Coppola’s arbitrary reduction of the equity ratio to 50% in the current case should be rejected.” 4 TR 870.

Second, with respect to Mr. Coppola’s claim that Consumers Energy’s equity balance should be artificially adjusted downward because “common equity capital infusions into Consumers Energy by the parent company are being funded to some extent by long term debt,” the Commission has considered and rejected various versions of this argument in at least four previous Consumers Energy rate cases. In Case Nos. U-15645, November 2, 2009 Order;

U-16191 May 17, 2010 Order; and U-16794, June 7, 2012 Order, the Attorney General recommended various arbitrary adjustments to the Company's capital structure based on the argument that Consumers Energy's capital infusions from its parent were leveraged by parent debt. The Commission rejected those arguments in each case. In the most recent of these cases, Case No. U-16794, the Commission wrote:

“The Commission agrees with the ALJ that the Attorney General's proposed capital structure should be rejected at this time. After Consumers adopted a holding company structure in the 1980s, the Commission has treated the utility as a stand-alone company for ratemaking purposes. In so doing, the Commission has established as a reasonable goal that Consumers maintain a capital structure roughly balanced between debt and equity, as is the case in this proceeding. From time to time, intervenors in Consumers' gas or electric rate cases have proposed the use of various hypothetical capital structures and the Commission has generally rejected these proposals. Indeed, on at least two recent occasions, the Commission had the opportunity to consider the Attorney General's argument regarding double leveraging by CMS. In both instances, the Commission rejected the proposal that CMS's capital structure should be substituted for that of Consumers' for ratemaking purposes. The Commission remains unconvinced of the validity of the Attorney General's contention that CMS's capital structure is reasonable for Consumers. Therefore, his exception is rejected.” MPSC Case No. U-16794, June 7, 2012 Order, page 43.

Similarly, in its July 31, 2017 Order in Case No. U-18124, the Commission adopted the findings and recommendations of the ALJ who found that the Attorney General's same argument that Consumers Energy's equity balance is, at least in part, funded by long-term debt from its parent company, “has been considered and rejected by the Commission.” Although the Attorney General does not explicitly recommend that the Commission outright substitute Consumers Energy's capital structure for that of its parent company in this case, he continues to use the reasoning behind that recommendation to promote imposing an artificial capital structure on Consumers Energy. However, the Commission has been clear that Consumers Energy will be

treated as a stand-alone company for ratemaking purposes. CMS Energy Corporation's debt should not be attributed to Consumers Energy, in whole or in part. Contrary to the Attorney General's insinuation, Consumers Energy's capital infusions from its parent company are necessary and appropriate investments for the health of the utility and the Attorney General's criticism and analysis in this regard has not merit and should, again, be rejected.

Finally, Mr. Denato also provided rebuttal responding to the Attorney General's claim that the Company's equity ratio is higher than the equity ratio of a peer group of companies.

Mr. Denato testified:

"The average equity ratio calculation for the proxy group on Mr. Coppola's Exhibit AG-29 uses the equity ratio at the parent holding company level. Ratios at the parent holding company level may be distorted by other, non-regulated balance sheet items. In addition, the source for Mr. Coppola's debt and equity balances is Securities and Exchange Commission reported financial statements which are prepared under Generally Accepted Accounting Principles. As described on page 24 of my direct testimony, there are differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis. This could further distort the equity ratios calculated on Mr. Coppola's Exhibit AG-96. As shown on page 1 of Exhibit A-82 (AJD-10), using data obtained from SNL Energy at the regulated subsidiary level, the average equity ratio (as a percentage of permanent capital) for Company witness Maddipati's ROE proxy group for fiscal year 2015 was approximately 53.3%. This is comparable to the equity ratio recommended for Consumers Energy's capital structure in my direct testimony. The analysis used by Mr. Coppola in support of a 50% equity ratio is not comparable or relevant and should not be considered in setting the Company's common equity balance in this case." 4 TR 874-875.

Mr. Coppola's argument fails because he was comparing Consumers Energy against utility holding companies instead of the subsidiary utilities themselves and using Securities and Exchange Commission ("SEC") data. Once those errors are corrected, Mr. Coppola's peer group analysis actually supports an equity ratio in line with that proposed by the Company.

**c. Response To Association Of Businesses Advocating
Tariff Equity**

Like the Attorney General, Association of Businesses Advocating Tariff Equity (“ABATE”) witness Billie S. LaConte begins by citing to the Commission’s directive in the Company’s electric rate case, Case No. U-17990 that moving to a 50/50 capital structure is appropriate in the absence of evidence suggesting otherwise. 7 TR 3422. She argues that Consumers Energy’s proposed capital structure results in movement toward a 50/50 goal, “but it does not follow the schedule presented by Mr. Denato in his rebuttal testimony in U-18322 . . .” 7 TR 3422. She also argues that: (i) the Company’s consideration of the implications of the TCJA are “premature;” (ii) the Company can maintain strong credit ratings and implement its capital expenditure program with a lower equity ratio, while taking advantage of low interest rates; (iii) using a lower ROE and equity ratio will not adversely impact the Company’s credit rating; and (iv) a higher common equity ratio will increase costs to ratepayers because equity is more expensive than debt. 7 TR 3423-3424. As a result, Ms. LaConte recommends an equity ratio of 52.0%. According to Ms. LaConte, the adjustment lowers the equity by approximately \$71 million and increases the amount of long-term debt by the same amount. 7 TR 3424. The effect of the adjustment to the debt-to equity ratio is a decrease in the revenue requirement of \$4 million (assuming an ROE of 8.77%). 7 TR 3424; Exhibit AB-11. As discussed below, these arguments are without merit and should be rejected.

As an initial matter, Ms. LaConte’s recommendations are not supported by any details or analyses – they are, essentially arguments without the necessary evidentiary support. In contrast, Mr. Denato offered a number of reasons in favor of the Company’s proposed equity ratio. For example, Mr. Denato discussed the implications of the TCJA in his proposed capital structure. 4 TR 853-859. Mr. Denato also indicated that a “[f]ailure to adapt and adjust to the Company’s

long-term equity ratio targets could have harmful implications to the Company's credit ratings, cost of capital, and ultimately customers." 4 TR 879. Further, the impact of a lower equity ratio and ROE, as reflected in Exhibit A-149 (ADJ-14), demonstrate a significant deterioration in credit metrics on the Company's credit quality as a result of the TCJA and a potentially lower equity ratio and ROE which justifies the proposed equity ratio of 52.5%. 4 TR 879.

Ms. LaConte offers no sound support for her recommendation and fails to account for the potential detrimental impacts if it were to be adopted. Thus, ABATE's arbitrary adjustments should be rejected. Instead, the Commission should adopt the capital structure proposed by the Company in this case, as shown in Exhibit A-147 (AJD-12) and in Appendix F, page 1, to this Initial Brief.

d. Response To Residential Customer Group

In his direct testimony, Residential Customer Group ("RCG") witness William A. Peloquin recommends that the Company's equity ratio be set at 52.00%. Mr. Peloquin arrives at this recommendation by interpreting the Commission's February 28, 2017 Order as a mandate to reach a balanced capital structure by 2022. Mr. Peloquin then calculates that a reduction in the equity ratio of 0.67% per year is required to reach that goal and, as a result, the equity ratio in this case should be set at 52.00% (52.67% approved in Case No. U-18322 minus 0.67% = 52.00%). 7 TR 3279. This approach has no basis in the record, is without merit, and should be rejected by the Commission.

As discussed above, in its February 28, 2017 Ordersystem a, the Commission did not require immediate action in reducing the Company's equity ratio and the passage of the TCJA, and the impacts associated therewith make the glide path to a 50% equity ratio by 2023 no longer reasonable. As such, maintaining an equity ratio of 52.5% will be appropriate for the foreseeable

future. 4 TR 881. Consequently, Mr. Peloquin's recommendation of a 52.00% equity ratio should be rejected.

C. Cost Rates

1. Return On Common Equity

a. Introduction And Summary Of Position

Consumers Energy's currently authorized ratemaking ROE for its electric business is 10.00%. This return was last set for Consumers Energy by the Commission in its March 29, 2018, Order in Case No. U-18322. In the current electric rate case, Consumers Energy witness Maddipati presented multiple analyses and arguments supporting an increase in the ROE to a rate of 10.75%. 3 TR 411. Mr. Maddipati's recommended 10.75% return is between the midpoint and the high end of his range of 10.00% to 11.00% despite the fact that the Company's significant infrastructure investment would justify an ROE potentially above the high end of this range. 3 TR 412. The 10.75% ROE recommended for Consumers Energy is 75 basis points higher than the 10.00% ROE which the Commission established for the Company in Case No. U-18322. 3 TR 469. Since the close of the record in the Company's last electric rate case, Congress enacted a significant revision in federal tax law with the passage of the TCJA, which has important and material impacts on the utility industry and the ROE analysis in this case. Enactment of the TCJA constitutes a radical change in the underlying economics impacting Consumers Energy. Failure to adopt an adequate ratemaking ROE in light of the passage of the TCJA could have a significant detrimental impact on the Company's ability to maintain its current favorable credit metrics. 3 TR 424-427, 476-487.

In the current electric rate case, Staff filed testimony in which it recommended the ROE for Consumers Energy be set at 9.75%. 6 TR 2504. The Attorney General's witness proposed a

return of 9.50%. 6 TR 2839. ABATE's witness proposed a return 8.77%. 7 TR 3364.⁸ All of these recommendations significantly understate investor expectations and the appropriate ROE for Consumers Energy's electric business. Furthermore, neither Staff, the Attorney General, nor ABATE incorporated the financial impacts of the TCJA in making their ROE recommendations, despite the fact that Congress enacted the TCJA nearly nine months before Staff and intervenor testimony was filed in this case, and despite the fact that credit rating agencies have warned about the significant detrimental impact of the TCJA on credit metrics in the utility industry generally. The parties' recommendations are less than the Company's presently authorized level of 10.00%, which was only recently established in the Commission's March 29, 2018 Order in Case No. U-18322. In that case, the Commission concluded the ROE should be set at a level higher than the return recommended by Staff or any of the intervenors. It should do so again in the current case.

Adopting recommendations of Staff, the Attorney General, and ABATE witnesses that the authorized return be reduced to 9.75% or below, would send the message to investors that Michigan is a volatile regulatory environment in which investors cannot depend upon consistent or fair regulatory treatment. As a result of the financial impacts of the TCJA, it would also jeopardize the Company's current favorable credit. The recommendations of Staff, the Attorney General, and ABATE do not appropriately balance the needs of investors with the needs of customers and do not give due consideration to economic, financial, and public policy considerations with regard to: (i) maintaining the positive track record established by the Company and the Commission over the past several years with investors and rating agencies;

⁸ MEC/NRDC/SC/EC/MEIBC witness Jester and Walmart Stores East, LP and Sam's East, Inc. (collectively "Walmart") witness Gregory W. Tillman also propose considerations that, in their view, should be taken into account when setting the ROE in this case. Neither of those witnesses offer a calculation proposing a specific ratemaking ROE to be used in this case.

(ii) the scope of Consumers Energy's investment plans; (iii) investor ROE expectations; (iv) risk aversion and cost of equity; and (v) the financial impacts of the TCJA on utility credit. See 3 TR 411-417, 419-442, 479-487.

Mr. Maddipati testified:

“Based on my interactions with investors and rating agencies, I conclude that they view the authorized ROE as a key signal provided by a utility commission and that the authorized ROE will affect their perception of the Michigan regulatory environment, credit of Consumers Energy, investment in Consumers Energy, and investment in Michigan. While investors view Michigan's regulatory environment as constructive, they are counting on continued stability in its regulatory decisions. If investors and credit rating agencies were to perceive the regulatory environment as deteriorating, this would quickly undercut the positive view that they currently hold.” 3 TR 427.

Mr. Maddipati provided both qualitative and quantitative support for his conclusion that the cost of common equity should be set at 10.75%, rather than at a level of 9.75% or less as proposed by the witnesses for Staff, the Attorney General, and ABATE. Among other things, Mr. Maddipati demonstrated that the enactment of the TCJA places upward pressure on the needed ROE, supporting an ROE of 10.75%. Consumers Energy submits that the Commission should set the authorized ROE at a level consistent with the record evidence in this case, including the impacts of the TCJA.

b. Applicable Principles

It is well established that equity investors in a public utility, such as Consumers Energy, are entitled to an ROE investment commensurate with investments of comparable risk, that earnings must be sufficient to assure financial soundness of a utility, and a utility must be able to earn a return that will allow it to maintain its credit and raise required capital. *Bluefield Water Works and Improvement Co v Pub Serv Comm of W Va*, 262 US 679, 693; 43 S Ct 675; 67 L Ed

1176 (1923), *Fed Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court stated in *Bluefield*:

“A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties” 262 US at 692. (Emphasis added.)

Similarly, the Supreme Court stated in *Hope*:

“By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital.” 320 US at 603.

These landmark Supreme Court decisions identify three criteria that a legally sufficient rate of return must satisfy in order to meet constitutional muster: (i) compensation for risk which is comparable to certain other companies of like risk; (ii) adequate return to ensure the financial soundness of the business; and (iii) sufficient return to maintain credit and attract capital. Rates which are not sufficient to yield a reasonable return on utility property at the time it is being used are unjust, unreasonable, and confiscatory. *Bluefield, supra*, 262 US at 690.

c. Qualitative Market And Risk Considerations

While the Supreme Court’s second criterion – ensuring a financially sound business – requires a principally inward-looking analysis of the financial circumstances particular to the utility under review, the remaining criteria articulated by the Supreme Court for a constitutionally sufficient ROE cannot be understood outside the context of circumstances affecting the broader market in which a utility operates. The question of whether a utility’s return will be sufficient to maintain its credit and to attract capital necessarily involves an

analysis of key economic indicators, such as the current and expected state of interest rates, and the attractiveness, as an investment opportunity, of one utility compared to other businesses that may be competing for those same investment dollars in the market. Likewise, it is not possible to compare the return required by one utility to the compensation enjoyed by other businesses of like risk without some understanding of the risks affecting all businesses collectively, or some businesses differently than others, under current and expected market conditions. Mr. Maddipati testified that “several of the inputs to my analysis included market observations that are impacted by the current state of the United States economy.” 3 TR 435. Mr. Maddipati also noted that the circumstances in the global economy also factor into investor decisions as a result of their “ripple effects” on the United States economy. 3 TR 435.

Furthermore, the cost of capital is an opportunity cost. Mr. Maddipati testified that the basic principle in setting a fair rate of return is the risk-return parity. 3 TR 417. Mr. Maddipati described this as the idea that the investment community determines the market price of financial securities such that the anticipated returns compensate the investor for the overall perceived risk of the specific security. 3 TR 417. Consequently, any review of the amount that should be included in ratemaking for a Company’s ROE must, in order to be meaningful, include analysis and consideration of current and expected market conditions and their effect on risk-return parity. In recommending an appropriate level for the Company’s ROE in this case, Mr. Maddipati considered the following factors affecting the risk-return analysis.

(i.) **Impacts From Federal Tax Reform**

In December 2017, Congress enacted the TCJA, which “brought sweeping changes to the federal tax system and has significant impacts on United States utilities.” 3 TR 424. For Consumers Energy, in particular, the TCJA resulted in a reduction in the revenue requirement associated with the Company’s then-current rates of \$113 million for its electric business and

\$48 million for its gas business. 3 TR 424. It is also expected to result in a refund to customers for amounts over-collected in rates from January 1, 2018 until base rates were reduced to reflect the new tax levels. See Consumers Energy's filings in Case Nos. U-20286 and U-20287. Finally, it is expected to result in additional reductions in customer rates over a period of time to reflect the \$1.6 billion accounting adjustment necessary to reflect the remeasurement of the Company's deferred federal income tax liabilities. 3 TR 424.⁹ Company witness Denato explained that: "[t]he TCJA had direct and significant impacts on the Company's cash flow, resulting in a weakening of the Company's financial credit metrics." 4 TR 853.

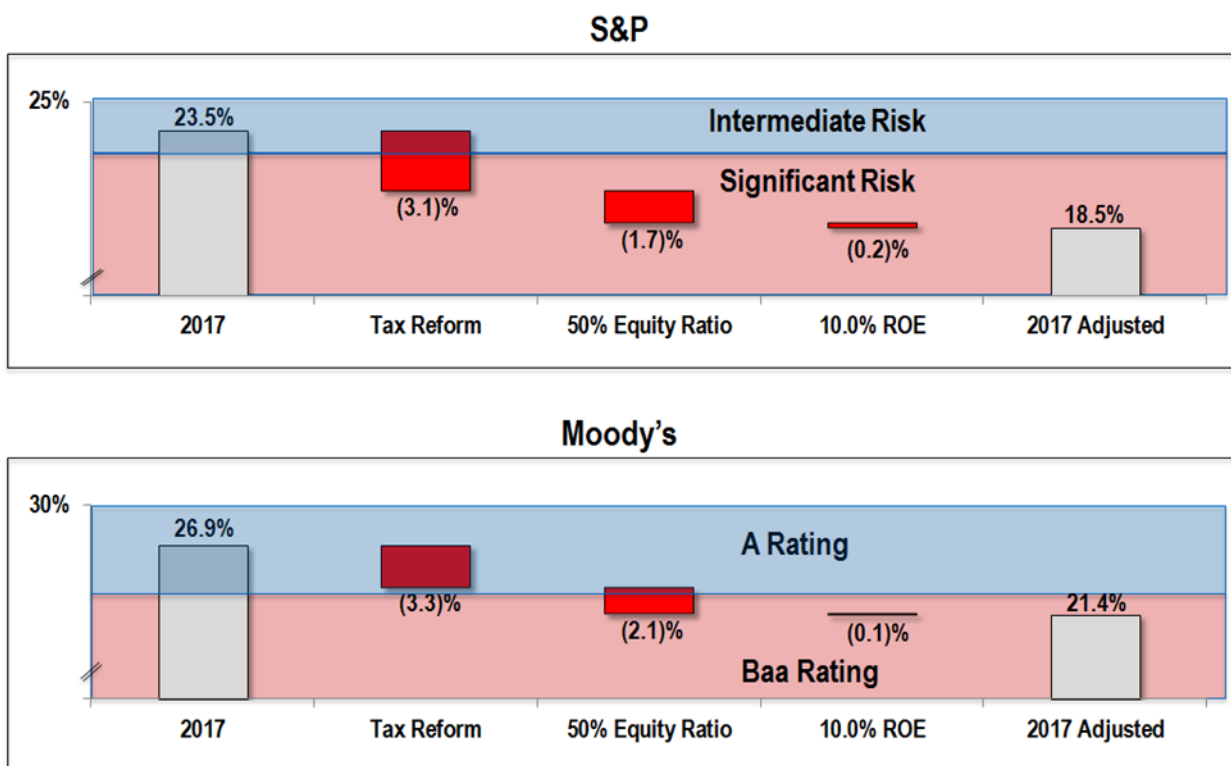
Mr. Maddipati provided testimony explaining the relationship between the TCJA and the Company's credit metrics. He explained:

"A key metric that is used to identify the credit-worthiness of a Company is the ratio of Funds From Operations ('FFO') to debt. Two key factors that help determine this ratio are the Company's ROE and equity ratio. Exhibit A-96 (SM-5) provides a mathematical development of how ROE and equity ratio determine a Company's FFO/debt ratio over the long term, assuming steady state conditions. An ROE of 10.75% and equity ratio of 52.49% would support an FFO/debt ratio of approximately 20%, which is a minimum level that would be supportive of the Company's credit. If the Commission were to maintain the Company's current ROE of 10.0% and the Company's 53.4% equity ratio as of December 31, 2017, it would support an FFO/debt ratio of approximately 20%. However, I do not believe an ROE of 10.0% meets the other key principles in setting a fair rate of return and, furthermore, I believe a 20% FFO/debt ratio would be at the bottom threshold of a credit supportive range and therefore maintaining cushion to the bottom of this range is important." 3 TR 426.

Mr. Denato performed a similar exercise in which he layered the impact of the TCJA into the actual historic Funds From Operations ("FFO") to Debt ratios provided by S&P and Moody's.

⁹ Mr. Maddipati's direct testimony in this proceeding reflects a \$1.5 billion adjustment based on then-current estimates. The Company's filing in its "Calculation C" case, Case No. U-20309 includes an updated calculation of the deferred federal income tax impact of the TCJA.

4 TR 855-856. Mr. Maddipati explained that the FFO to Debt metrics for the Company at the end of 2017 (immediately prior to the TCJA going into effect) are at the low end of the “Intermediate” risk rating category used by S&P and in the middle of the “A” rating category used by Moody’s. 3 TR 484. He also included diagrams showing the impact of: (i) tax reform; (ii) a 50% equity layer; and (iii) a 10.00% ROE on the Company’s current S&P and Moody’s ratings relative to the thresholds for each of those credit rating agencies’ next lower ratings tier. 3 TR 485; see also 4 TR 857. The diagrams are reproduced below:



Mr. Maddipati testified that credit rating agencies have published reports indicating that the TCJA is credit-negative across the entire utility sector¹⁰ and have specifically identified ROEs and equity ratios established in utility rate cases as key tools for mitigating the detrimental impact of the TCJA on utility credit metrics. 3 TR 424-425. As a result, Mr. Maddipati notes

¹⁰ In fact, in June 2018, Moody’s took the unprecedented step of shifting its outlook for the entire regulated utility sector to “negative.” 3 TR 480.

that the regulatory response to the impacts of the TCJA will play a critical factor in mitigating these credit risks. 3 TR 425.

Despite the widely communicated impact of the TCJA on the entire utility sector, and the evidence offered by the Company on the impact of the TCJA on Consumers Energy's credit metrics in particular, none of the other parties addressing the subject of Consumers Energy's ROE in this case made any adjustment to their recommendations to account for the impact of the TCJA. 3 TR 481. Each of the other ROE witnesses in this case either disregarded the impacts of the TCJA or they dismissed its significance without any meaningful analysis of its impact. 3 TR 481-482, 486-491. Mr. Maddipati testified: "Tax reform has been the focus for investors, lenders, and ratings agencies for this entire calendar year, so the fact that Staff, the AG, and ABATE witnesses failed to assess the impact of the TCJA on their ROE analysis should give the Commission considerable pause." 3 TR 482. Any ROE proposals in this case that do not include some adjustment to account for the impact of the TCJA on the financial health of the utility should be given little weight or should be disregarded entirely.

(ii.) Economic Outlook, Interest Rates, And Risk Aversion

Mr. Maddipati testified that there are a number of circumstances in both the United States and global economies that are currently adding to investors' risk perceptions. 3 TR 435-440. In the United States, Mr. Maddipati pointed to the combination of rising interest rates and the enactment of the TCJA (discussed above), which have resulted in an increase in growth opportunities from investments with increased profits from lower taxes, as well as an increase in the attractiveness of less risky alternatives such as United States Treasuries. 3 TR 435. This, in turn, has resulted in increased competition for capital investment to fund projects as utility stocks begin to underperform relative to the broader market. 3 TR 435. Mr. Maddipati testified that

these factors have increased uncertainty and utility investor risk in the market. 3 TR 435. Mr. Maddipati also noted recent international events, such as: (i) the United States' recent transition toward taking a harder line on international trade; (ii) establishing import tariffs; and (iii) threatening a trade war with China, amongst other countries, which have added to economic uncertainty and increased volatility in global markets. 3 TR 435-436. Mr. Maddipati pointed out that the recent United States elections have resulted in increased optimism for a pro-growth economic policy domestically and fueled an equity market rally, while the passage of tax cuts and increased federal spending has increased the potential for long-term deficits. 3 TR 436. Mr. Maddipati's direct testimony included a chart showing that the Economic Policy Uncertainty Index for the United States, as posted by the Federal Reserve Bank of St. Louis, has increased from an average "uncertainty" score of 72 before the election, to an average "uncertainty" score of 101 after the election – a 29% increase. 3 TR 437.

Mr. Maddipati testified that the Federal Reserve recently reaffirmed, in a March 21, 2018 press release, its "accommodative" policy of the last several years to maintain low long-term interest rates through a series of largescale asset purchase programs. 3 TR 428. Mr. Maddipati noted that the Federal Reserve's balance sheet has both grown dramatically in recent years and it has shifted in composition to a portfolio consisting of a greater proportion of longer duration assets (i.e., those with maturities over 10 years). 3 TR 428-429. Mr. Maddipati explained that, at the same time, central banks in other countries around the world have also reduced interest rates in response to poor economic conditions. 3 TR 429. These policies have resulted in yields that make the rates offered by long-term United States Treasuries more attractive to investors at the same time that the supply of those Treasuries has been very low. 3 TR 430. The result is that long-term rates have been artificially suppressed. 3 TR 430.

Mr. Maddipati also testified regarding his analysis of how interest rates will move going forward. He testified that the Federal Reserve has kept short-term rates at, or near zero, and as a result, its purchase of longer-duration assets has kept longer-term rates artificially low. 3 TR

430. Mr. Maddipati testified:

“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 has continued with five additional rate hikes . . . This series of rate hikes in the Federal Funds Rate is substantial, but this move in short-term interest rates do not correspond with a move in long-term interest rates.” 3 TR 430-431.

Mr. Maddipati testified:

“Analysts tend to agree that when interest rates begin to rise, they increase quickly and in an unpredictable manner. This volatility leads to higher risk which, in turn, demands a higher required return on investments.” 3 TR 440.

The recent announcements by the Federal Reserve also contribute to the uncertainty and volatility of the markets in the near term. Mr. Maddipati testified:

“Greater volatility, or large swings up or down, in value in the financial markets increases overall investor risk. During times of extreme fluctuations in investments, there is greater uncertainty and risk among the investment community. As the relative amount of risk in an investment increases, an investor will require a higher return on that investment to compensate for the risk level. The volatility in the financial markets should be taken into consideration in developing the appropriate ROE for the Company.

“Interest rates have been volatile given the uncertainty regarding the Federal Reserve’s decision of when, and by how much, to raise interest rates along with the pace of unwinding the balance sheet, and the threat of increased inflationary pressures in the market. The rapid change in volatility and investor sentiment is another reason I have focused my analyses towards longer-term averages for market observables. There is a consensus among economists that interest rates will continue to rise and revert to normal levels , as indicated by various interest rate forecasts. While the Federal

Reserve will try to make this process as smooth as possible, a sudden, abrupt rise in the interest rates cannot be ruled out. It is hard to predict the timing of such abrupt movements, and this unpredictability adds additional risks that are not captured by using the average projected interest rates.” 3 TR 437-438.

Mr. Maddipati noted that the Federal Energy Regulatory Commission (“FERC”) has recognized these factors as creating “anomalous market conditions.” 3 TR 416. Mr. Maddipati explained that these anomalous market conditions require adjustments to the quantitative models typically utilized to estimate ratemaking ROE. 3 TR 416-417.

The analyses offered by witnesses for the Attorney General and ABATE in this case fail to account for the United States and global market conditions described above. Staff’s ROE witness claims that the market conditions discussed above are not “anomalous,” pointing to recent increases in the short-term interest rate increases by the Federal Reserve. 6 TR 2515. In rebuttal, Mr. Maddipati testified:

“I find this claim surprising, as the recognition of anomalous market conditions in present day market conditions is not unique to the Company. Mr. Megginson focuses on interest rate hikes that have been imposed on short-term interest rates and chooses to ignore the continued state of long-term interest rates. The issue need not be debated by others, as Mr. Megginson himself, on page 27 of his testimony, credits the Federal Reserve’s ability, through its monetary policy, to manage the economy as it sees fit based on market forces.

“My direct testimony quotes a Federal Reserve definition of accommodative monetary policy as aiming to make interest rates sufficiently low. Given this undisputed record of evidence from the very source that Mr. Megginson credits with the power and control to manage interest rates and the economy, it is curious for Mr. Megginson to refute that anomalous market conditions exist, and that the Federal Reserve’s actions have artificially suppressed long-term interest rates. To do so not only contradicts his own testimony, but it contradicts the policy statements made by Federal Reserve Chairman Powell himself. Further, Mr. Megginson’s belief that multiple years of anomalous market conditions should suddenly be considered normal compared to generations in which current market forces have been absent is simply not reasonable.

Even if these conditions are now the new normal, . . . the ‘new normal’ years certainly cannot be reasonably compared directly to the previous generations of data, for which there were no such accommodative policies creating anomalous conditions and altering market forces.” 3 TR 511-512.

In other words, even if current market conditions are now “normal,” they are not the same as the market conditions in the past and cannot be used as an appropriate basis of comparison. Some adjustment must be made. Staff’s ROE witness appears to acknowledge Mr. Maddipati’s point about the incomparability between the historical inputs and the estimation of a forward-looking ROE under current market conditions because, notwithstanding his arguments that no anomalous conditions exist, he makes an adjustment to his quantitative analyses expressly for the purpose of overcoming the mismatch between his historical inputs and the appropriate inputs under current market conditions. Staff’s adjustment will be discussed in more detail below.

Having failed to adequately take into consideration the impact of the TCJA, rising short-term interest rates, and other anomalous market conditions, the ROE recommendations of the Attorney General, ABATE, and other intervenors significantly understate the return investors would expect the utility to earn. As will be discussed in more detail below, Staff’s ROE recommendation also understates the return investors would expect because Staff’s attempt to adjust for current market conditions was executed improperly.

(iii.) Investor ROE Expectations

The authorized ROE is one of the most important parameters used by analysts to determine the attractiveness of investing in utilities. 3 TR 412. Mr. Maddipati testified that investors generally view the present overall regulatory environment as supportive. 3 TR 419, 494. However, he emphasized that investors look for continued confirmation that the Commission understands the investment community and the importance of returns in attracting

capital to Michigan. 3 TR 419. In his testimony, Mr. Maddipati quoted several investment analyst sources that confirm the current positive perception of the Michigan regulatory environment. 3 TR 421-422. He also noted that Michigan's constructive regulatory environment is "built into investors' expectations and that a regression from the current status would be viewed negatively." 3 TR 422. However, Mr. Maddipati noted that at least some analysts expressed recent concerns about "ROE creep" and the continued supportiveness of the regulatory environment in Michigan. 3 TR 421-423. Mr. Maddipati cautioned that: "[i]f investors and credit rating agencies were to perceive the regulatory environment as deteriorating, this would quickly undercut the positive view that they currently hold." 3 TR 427. Concerns that ROE could decline, or that regulatory outcomes could become less predictable, may cause a reassessment of investors current positive view of Michigan's regulatory environment. 3 TR 494.

It is not safe to presume, as Staff, the Attorney General, and ABATE apparently have, that significantly lowering the ROE would still result in Michigan being viewed as having a constructive regulatory framework. Such a conclusion would be incorrect. If adopted, it could result in undoing the very constructive regulatory environment that has facilitated Consumers Energy's successful capital attraction activities over the past several years, and garnered such positive reviews by the investment community.

Consumers Energy presented evidence that, from 2018 to 2027, the Company plans to continue making significant capital expenditures in its electric business to provide added safety, reliability, value, and sustainability benefits for customers. 2 TR 62. In fact, Mr. Maddipati testified that over the next 10 years, the Company plans to invest at least \$18 billion, possibly as much as \$25 billion, on a total company basis. 3 TR 440. Company witness Torrey testified that

a significant amount of that – approximately 55% – will involve investment in electric infrastructure. 2 TR 62. The Company’s capital plans over the next year are consistent with the findings of Governor Rick Snyder’s 21st Century Infrastructure Commission Report. Exhibit A-152 (SM-17). The advisory board noted in their published report the need to modernize the state of Michigan’s energy infrastructure, and also recognized utilities as the mechanism for funding this necessary investment. 3 TR 493.

Mr. Maddipati testified that, during this period of needed capital investment, it is imperative that the Company maintain a supportive ROE. 3 TR 440. Reducing the ROE, as proposed by Staff, the Attorney General, and ABATE, could lead to increases in cost of capital or limit access to capital. 3 TR 440. Neither would be in the best interest of customers. 3 TR 440. According to Mr. Maddipati:

“Capital is finite. Not all projects or investments, therefore, can be funded, and the management team of a utility must decide which investments are most beneficial to customers and investors and should ultimately 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 private enterprise to make an investment decision. Capital invested in the utility needs to be weighed against other potential investments available to investors. Further, as fiduciaries, the management team must weigh whether investment in the utility provides sufficient risk-adjusted returns relative to other options, including gas utility investments, investments in other jurisdictions, non-regulated investments, or returning capital to shareowners in the form of dividends or share repurchases. While the investment community generally views the regulatory environment in Michigan as constructive and supportive, concerns that ROEs could decline, or that regulatory outcomes could become less predictable, may cause a reassessment of that view.” 3 TR 493-494.

Put another way, if investors and management teams perceive the risk that invested capital would be subject to downward pressure in the future, they will be increasingly cautious about current investments in order to avoid this risk. 3 TR 442.

Mr. Maddipati noted that the Commission has already reduced the Company's ratemaking ROE by 30 basis points in a little over 24 months. 3 TR 493. Although there has been no change in circumstances since the Commission's most recent ROE reduction that would warrant any further downgrade in the Company's ROE; Staff, the Attorney General, and ABATE, nevertheless propose reductions ranging from 25 basis points to 123 basis points. Such dramatic reductions would send negative signals to investors. Any authorized return lower than the Company's current authorized rate of 10.00%, as Staff, the Attorney General, and ABATE have proposed, would not be reasonable.

In contrast, a return of 10.75% as requested by the Company is within the range of reasonable returns, and adopting a 10.75% return in this case will help protect the Company's credit, assure that Consumers Energy continues to have reasonable access to capital on reasonable terms and conditions, as well as satisfying the other criteria required for a constitutionally sufficient ROE under the *Hope* and *Bluefield* precedents.

d. Quantitative Methodologies And Conclusions

Under principles set forth in the *Hope* and *Bluefield* decisions, it is necessary to determine a return that will reflect the investor-perceived risk of the utility being examined as compared with alternative investments and compensate investors for that risk. When the common stock of a public utility is not publicly traded, as with Consumers Energy, indirect or proxy approaches must be used to calculate an appropriate return on common equity. 3 TR 443. Since no one method of comparison perfectly simulates the operation of the market, multiple models combined with an assessment of the marketplace, as discussed above, are typically used in evaluating the market required cost rate for common equity. 3 TR 418.

(i.) Proxy Group Selection Criteria

For his analyses, Mr. Maddipati utilized the S&P Global published data set to select a proxy group of publicly traded electric utility companies. 3 TR 443; Exhibit A-14 (SM-1), Schedule D-5, page 1. In order to meet the criteria for inclusion in the proxy group, each company had to: (i) have regulated generation capacity greater than 2,000 MW; (ii) have net Property Plant & Equipment between \$5 billion and \$60 billion; (iii) be headquartered in and have the vast majority of operations in the United States; (iv) have a dividend payout ratio of in the last 12 months greater, than or equal to, 60%; (v) not be a recent merger target or be engaged in significant restructuring; and (vi) have bonds rated at, or above, a minimum investment grade of Baa3 by Moody's and BBB- by S&P. 3 TR 443-444. The application of these screening criteria resulted in a group of 11 companies. 3 TR 444. The list of the proxy group companies is shown in Exhibit A-14 (SM-1), Schedule D-5, page 1, column (b).

Staff, the Attorney General, and ABATE each offered various criticisms of the proxy group selected by Consumers Energy. Mr. Maddipati pointed out in rebuttal testimony that each of the other ROE witnesses in this case utilized a proxy group with many of the same companies as Consumers Energy used, although there was no consensus among the other parties about the appropriate proxy group. 3 TR 498-499. However, Mr. Maddipati also pointed out that these minor differences in the final composition of each parties' proxy groups did not drive the difference in the results of their analyses. 3 TR 499. To illustrate the point, Mr. Maddipati re-ran his ROE analyses, using each of the other ROE witnesses' proxy groups, and the proper

inputs for each model is discussed in more detail below and presented the following table comparing the results:¹¹

Model	Method	Staff	AG	ABATE	Company
CAPM	Normalized ROE	9.89%	9.86%	9.58%	9.78%
CAPM	Projected Risk Premium ROE	11.79%	11.74%	11.29%	11.60%
ECAPM	Normalized ROE	10.35%	10.32%	10.11%	10.26%
ECAPM	Projected Risk Premium ROE	12.25%	12.20%	11.82%	12.09%
DCF	Analyst Consensus	9.65%	9.57%	9.56%	10.13%
DCF	Company Guidance	9.89%	9.90%	9.93%	10.33%
COMP. EARNINGS		10.69%	10.69%	10.81%	11.33%
Average		10.65%	10.61%	10.44%	10.79%

Analyzing these results, Mr. Maddipati testified:

“The results demonstrate that the outputs of individual quantitative models are much more in line with my ROE recommendation of 10% - 11%, as the averages of the quantitative models for Staff, the AG, and ABATE are each either at or above 10.44% and all very supportive of a 10.75% ROE in this case. Further, this analysis should make clear that in this case, the selection of the proxy and inclusion of flotation costs are not primary drivers of the differences in ROEs advocated by each of the witnesses. As such, I believe that the focus of discussion in this case should be upon the proper application of quantitative models rather than on the composition of the particular proxy groups proposed by the parties or the inclusion of flotation costs, which can be addressed separately.” 3 TR 502.

Though there are some slight variations in the proxy groups utilized by each ROE witness in this case, the differences are essentially immaterial. As recommended by Mr. Maddipati, the focus of the Commission’s review should be on the proper application of the quantitative models.

¹¹ The table also removed the impact of Mr. Maddipati’s proposal to include a flotation cost adjustment to show that neither issue, even when combined, is a principal driver of the difference between the Company’s and the other parties’ ROE results. 3 TR 501.

(ii.) Application Of Quantitative Models

Mr. Maddipati assessed the ROE for Consumers Energy's electric operations using multiple methodologies in combination with assessments of the market and risk environment for Consumers Energy. Among other things, Mr. Maddipati: (i) studied the current outlook of the national economy and capital markets; (ii) analyzed the investor perceptions of the Michigan regulatory environment and risk factors associated with investment in Consumers Energy; (iii) performed standard quantitative analyses to determine the cost of equity of a proxy group of companies and compared the risk-return profile of Consumers Energy with other similar investments; and (iv) considered current trends in the business climate for electric utilities and Consumers Energy in particular. 3 TR 419-442, 445-466.

As part of his assessment, Mr. Maddipati undertook quantitative analyses using the Capital Asset Pricing Model ("CAPM") and Empirical CAPM ("ECAPM"), a Risk Premium analysis, the Discounted Cash Flow ("DCF") model, and a Comparable Earnings Analysis. These analyses are described at 3 TR 445-466. The ROE witnesses for Staff, the Attorney General, and ABATE offer criticisms of various aspects of the Company's quantitative analyses, which Mr. Maddipati responded to in his rebuttal testimony. See, generally, 3 TR 496-535.

Several of the analyses performed by Mr. Maddipati (i.e., CAPM, ECAPM, and Risk Premium) calculated expected ROE at some level of premium above a risk-free rate. Traditionally, the risk-free rate used to perform these analyses is a projection of yields on United States Treasury Bonds. However, as discussed above, the Federal Reserve is currently engaged in monetary policy designed to keep long-term rates artificially suppressed. 3 TR 427-433. Mr. Maddipati noted in his direct testimony, that one of the key components in many of the quantitative models is the interest rate on long-term government bonds as a benchmark. 3 TR

430. However, Mr. Maddipati explained that “in an environment where the Federal Reserve is purposefully keeping long-term interest rates low, these models become less reliable, which is well documented by not only the Federal Reserve but academics and market practitioners.” 3 TR

430. Mr. Maddipati testified:

“Based on my extensive experience and conversations with utility investors, and in particular investors in Consumers Energy, it is clear that investors’ expectations for returns do not simply decrease because of extraordinary intervention by central banks to lower rates.” 3 TR 430.

Mr. Maddipati noted in his testimony that utility stocks are particularly sensitive to interest rates and utilizing projected interest rates, which have considerable variability, would underestimate the Company’s required ROE. 3 TR 416, 436, 454. Furthermore, Mr. Maddipati testified that the results of standard quantitative models often make assumptions that do not fully reflect the returns that investors expect given current economic and financial conditions. 3 TR

419. Mr. Maddipati explained:

“The models are based on the assumption that economic conditions are relatively stable and that current market inputs are reflective of their long-term outlook. That assumption is not currently being met. There is significant uncertainty, mainly because of the unprecedented amount of intervention by central banks during the last several years as well as around the major impacts of the TCJA on the economy and the credit of utility companies. As a result, the models tend to understate the return that investors currently require to compensate them for risk.” 3 TR 419.

To mitigate the impacts of these temporary economic conditions and uncertainty, Mr. Maddipati made appropriate adjustments to the inputs used in his CAPM, ECAPM, and Risk Premium analyses using two alternative methods. In one method, he used a “normalized” risk-free rate based on the average income return of long-term government bonds from 1926 to 2017, as reported by Ibbotson, together with a historical risk premium. 3 TR 450, 455, 458-459.

In the second method, Mr. Maddipati estimated a more accurate “projected” equity risk premium consistent with research indicating higher equity risk premiums in low interest rate environments, together with published forecasts of the risk-free rate. 3 TR 450-451, 455, 459.

Despite the well-documented intervention by central banks discussed above, which renders the assumptions behind the traditional CAPM and Risk Premium models inaccurate, the Attorney General’s and ABATE’s witnesses nevertheless each performed CAPM analyses using projections of yields on United States Treasury Bonds reflecting the current non-market based administered interest rates and historical risk premiums, that are not reflective of investor expectations under current market conditions. 6 TR 2851; 7 TR 3398. These treasury rates and risk premiums are not tied to current market forces, as Mr. Maddipati pointed out in his testimony. 3 TR 427-433, 435-440. Similarly, the Attorney General performed a Risk Premium analysis that also fails to adjust the risk premium to current market conditions. 6 TR 2852-2853.

Staff also performed a CAPM analysis using a historical risk premium with a projected risk-free rate which, as discussed above, is incorrect. However, Staff also performed a second CAPM analysis. To its credit, Staff recognized that an adjustment to the CAPM and Risk Premium analyses would be necessary because they are forward-looking models and the use of historical inputs that are not reflective of future market conditions would not be appropriate.¹² 6 TR 2512-2513. This is the same point that Mr. Maddipati has made in this case and other recent rate cases. Like Mr. Maddipati, Staff calculated a forecasted market risk premium to be used in place of its historical average market risk premium in its CAPM analysis. 6 TR

¹² Staff makes this adjustment despite arguing, as discussed above, that the market conditions that Mr. Maddipati and FERC have described as “anomalous” are not actually anomalous. 6 TR 2515. Staff offers no explanation for the inconsistency between its unsupported claim that market conditions are not anomalous and its adjustment to overcome the deficiencies in using historical inputs to calculate forward-looking ROEs under current market conditions.

2512-2513; Exhibit S-4, Schedule D-5, page 8. Staff also used a risk premium for its proxy group derived from this forecasted market risk premium in its Risk Premium analysis. 6 TR 2521; Exhibit S-4, Schedule D-5, page 11.

However, Staff did not properly execute its adjustment to the CAPM (and by extension the Risk Premium) analysis. In order to calculate its forecasted market risk premium, Staff added a median dividend yield value to a stock price appreciation value. 6 TR 2513. Staff made two errors in executing its calculation of the projected market return. First, Staff used inappropriate and misaligned inputs. Staff attempted to estimate an annual growth rate using a price appreciation forecast over the next three to five years (6 TR 2513), which Mr. Maddipati explained in rebuttal testimony, is well outside of the test year and not aligned with Staff's own dividend yield value. 3 TR 510. Mr. Maddipati explained: "Failure to align the dividend yield and market return periods can cause the projected total return to be understated, since dividends will potentially grow to support the stock growth." 3 TR 511. Second, Staff used a single estimate from Value Line for the 1,700 stocks in the New York Stock Exchange ("NYSE"), which is not conceptually sound. Mr. Maddipati explained that the 1,700 stocks listed on the NYSE include a number of stocks for companies that are small or illiquid and are not reflective of the market risk premium demanded for a larger company. Instead, Mr. Maddipati explained that using returns for larger companies, such as those in the S&P 500, are more accurate given the size of the companies in both Staff's and the Company's proxy groups. As a result of these two errors, Staff's forecasted market premium is understated.

Since each of the other parties' quantitative ROE analyses rely on the use of an equity risk premium failed to appropriately adjust for artificially low treasury rates or historical risk

premiums that do not correspond to current market conditions, their respective CAPM and Risk Premium analyses understate the Company's required ROE and should be rejected.

None of the other ROE witnesses in this case performed an ECAPM analysis. This weakens the robustness of their respective analyses for two reasons. First, by excluding an ECAPM analysis, the other ROE witnesses simply have fewer data points for evaluating the reasonableness of their ROE estimates. Second, Mr. Maddipati testified that the ECAPM addresses a well-documented short-comings in the CAPM analysis by incorporating an "alpha" adjustment to the CAPM calculation. 3 TR 454. The CAPM analysis tends to overstate the sensitivity of the cost of capital to beta,¹³ which means that low beta assets tend to have higher average returns than would be predicted, while high beta assets have lower returns. 3 TR 454. By excluding an ECAPM analysis, the other parties' ROE witnesses make no correction for this known short-coming in the CAPM.

Staff explained its decision not to use an ECAPM analysis by claiming that Staff's inputs to its CAPM analysis, which include Value Line adjusted betas and a long-term risk-free rate, render the adjustments made by ECAPM unnecessary. 6 TR 2517-2520. ABATE's ROE witness also claimed that ECAPM is unnecessary if adjusted betas are used. 7 TR 3409. The Attorney General's ROE witness also criticize the use of ECAPM, but offered no analysis of his own regarding the conceptual validity of the model.

With respect to the use of Value Line adjusted betas in the ECAPM analysis, Mr. Maddipati provided the following testimony:

¹³ Mr. Maddipati explained that the beta variable utilized in the CAPM and ECAPM analyses "is used as an indication of the relative risk of an investment to the risk of a market portfolio consisting of all types of risk-oriented assets." 3 TR 445. In other words, beta offers a comparison of how risky an individual investment is compared to investments in the market as a whole. Mr. Maddipati explained that companies whose securities have betas greater than 1.00 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. 3 TR 446.

“Adjusted betas were used in the ECAPM analysis as part of the decisions made in several regulatory jurisdictions including Maryland, Mississippi, and Alberta. Furthermore, in Dr. Morin’s book, *The New Regulatory Finance*, he explicitly states the use of adjusted beta is necessary and that suggestions to the contrary are erroneous:

“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.**”
3 TR 457-458 (emphasis in testimony, not in original source material).

Although ABATE witness LaConte argued in her direct testimony that: “[t]here is no need to perform an ECAPM analysis as it results in re-adjusting the formula to capture a phenomenon that the adjusted beta has already corrected” (7 TR 3409). Mr. Maddipati pointed out in his rebuttal testimony that, in a proceeding before the Missouri Public Service Commission in 2011, Ms. LaConte also performed an ECAPM analysis to “re-adjust” the adjusted Value Line betas. 3 TR 531-532. Explaining her analysis in that proceeding, Ms. LaConte’s exact words were: “To be fair, I re-adjusted the Value Line betas and used this

re-adjusted beta to calculate the ROE using the CAPM method (this is also known as the Empirical Capital Asset Pricing Model, ECAPM).” 3 TR 532. Consumers Energy agrees that the ECAPM adjustment is necessary in order “[t]o be fair.” Despite Staff’s and ABATE’s arguments to the contrary, the evidence in this case shows that the Value Line adjustments to beta do not render the ECAPM analysis unnecessary.

With respect to the issue of the use of long-term risk-free rates, Staff’s own testimony undermines its claim that the use of long-term risk-free rates somehow eliminates the need for ECAPM’s alpha adjustment. Staff included a graph on page 31 of Mr. Megginson’s direct testimony, that shows a linear relationship between the average cost of equity capital and beta risk produced using the CAPM, the ECAPM, and another CAPM using a long-term risk-free rate. The graph shows that the use of the CAPM using the long-term risk-free rate produces a line that is somewhat flatter than the original CAPM line, but the graph clearly depicts that the resulting line is still not as flat as the line produced with the ECAPM results. 6 TR 2519. Since the difference between the lines represents the alpha adjustment that is needed under ECAPM, Staff’s own graph shows that the use of long-term risk-free rates only partially accounts for the short-comings observed in the original CAPM model. In other words, the use of long-term risk-free rates does not eliminate the need for an alpha adjustment; it means that the alpha adjustment just needs to be a little smaller. Mr. Maddipati used a low alpha adjustment of only 1.5% to perform his ECAPM, which is consistent with the use of a long-term risk-free rate. 3 TR 455. In rebuttal, Mr. Maddipati testified:

“Mr. Megginson seems to be indicating that his use of a Value Line Beta and long-term treasury rates addresses the short-comings of CAPM and make ECAPM unnecessary. This is simply untrue and is demonstrated by other practitioners who use ECAPM with both long-term Treasury Rates and Value Line Beta. Mr. Megginson has presented no third-party academic or

practitioner support to corroborate his claim that the CAPM analysis he performed addresses the shortcoming addressed by ECAPM. The ECAPM does increase the resulting ROE output, but this should not be a surprise, as it corrects for the understated return that exists for low beta securities.” 3 TR 515.

There is no merit in Staff’s claim that its choice of inputs into its CAPM analysis somehow eliminated the well-documented short-comings in the CAPM. Furthermore, the other parties to this case have repeatedly argued against the use of the ECAPM in the ROE analysis over the course of many rate cases. Despite many repeated entreaties to the Commission to reject the use of ECAPM, the Commission has never issued an ROE decision finding that an ECAPM is an inappropriate methodology for estimating ROE. Contrary to the arguments of Staff’s, the Attorney General’s, and ABATE’s ROE witnesses, the ECAPM adjustment is still appropriate and provides another useful insight into the estimation of ROE in this case.

For his DCF analysis, Mr. Maddipati also utilized two alternative methodologies.

Mr. Maddipati explained:

“One of the difficult steps in applying the DCF model is determining the appropriate growth rate. The DCF analysis should utilize, whenever possible, a single ‘long-term’ (i.e., perpetual) dividend growth rate of the company required by the investors who own the company’s stock. However, analysts do not typically provide long-term growth for dividends, and therefore I used analyst projections for dividends over the next three years to estimate dividend growth. In addition to analyst dividend growth, company management will often provide guidance for projected growth, and therefore I performed two methods of analysis: one which utilized consensus analyst dividend per share growth estimates, and the other which utilized the mid-point of company long-term growth guidance.” 3 TR 463. (Emphasis in original.)

Similar to the CAPM, ECAPM, and Risk Premium analyses, Mr. Maddipati cautions against over-reliance on DCF model results given current market conditions. Mr. Maddipati cited recent findings by FERC supporting his concerns. According to Mr. Maddipati:

“FERC explicitly acknowledged throughout Opinion 551 that actions by the Federal Reserve have created ‘anomalous market conditions.’ Additionally, FERC noted that these conditions have proven the mechanical application of certain quantitative models to be insufficient to satisfy the standards for setting ROE as outlined in the landmark *Hope* and *Bluefield* Supreme Court decisions.”
3 TR 416,

In particular, FERC stated:

“[W]e find that current capital market conditions may cause the mechanical application of the DCF methodology to produce an ROE that does not meet the requirements of *Hope* and *Bluefield*.”
Exhibit A-94 (SM-3), page 62 (emphasis added).

No other party that performed a DCF analysis makes any adjustment to the model or inputs to account for the effect of current market conditions or discusses the impact of the anomalous market conditions on the proper way to interpret and analyze its DCF results.

Mr. Maddipati also notes that Staff’s, the Attorney General’s, and ABATE’s witnesses all use earnings growth rates in their DCF analyses, . 3 TR 506-507, 524-525, 532-533. Even though the Attorney General’s and ABATE’s witnesses explicitly acknowledge in their testimony that dividend growth is the correct input into the model (6 TR 2846; 7 TR 3393-3394), all three witnesses nevertheless use some form of earnings growth. 3 TR 506-507, 524-525, 532-533. Earnings growth is used as a proxy for dividend growth when dividend growth is not available. But, no party explains why it is appropriate to use earnings growth when dividend growth data is available as it is in this case. Correcting for each parties’ less appropriate inputs would result in materially higher ROE estimates.

Finally, Mr. Maddipati testified that the Company’s 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. 3 TR 465. Mr. Maddipati explained that the rationale behind the model is that 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. 3 TR 465. Once again, the Attorney General and ABATE criticize the Company's use of the Comparable Earnings analysis, but provide no academic support for their criticism. Attorney General witness Coppola, in particular, claimed that the Comparable Earnings method is not "academically sound" and characterized it as an "alternative" method of estimating ROE. 6 TR 2861. However, in his rebuttal testimony, Mr. Maddipati pointed out:

"Mr. Coppola seems to be unfamiliar with the history of ROE models. The DCF and CAPM model were developed decades after *Hope* and *Bluefield* were decided. For years, the Comparable Earnings analysis was the standard for determining rate cases. Newer models and techniques have been developed, but the Comparable Earnings analysis is still relevant and in use today. In Case No. U-16794, the Commission specifically considered and gave weight to determining the ROE using the Comparable Earnings analysis, and FERC in Opinion 551 also utilized the Comparable Earnings analysis as a methodology." 3 TR 525. (Emphasis in original)

The Company's Comparable Earning method has a long history of use in estimating ROE for utility rate cases that pre-dates any of the other quantitative methodologies relied upon by the parties today, and the Commission has affirmatively recognized it as an appropriate and helpful method for estimating ROE. There is simply no basis for the Attorney General's and ABATE's criticism of this methodology.

Using the appropriate analyses recommended by Mr. Maddipati for each of his quantitative analyses, the proxy group returns shown in Exhibit A-14 (SM-1), Schedule D-5, page 14, are as follows:

<u>Proxy Group/Utility Results</u>	<u>Average</u>	<u>Median</u>
Normalized Capital Asset Pricing Model	9.96%	9.77%
Projected Risk Premium Capital Asset Pricing Model	11.78%	11.48%
Normalized Empirical Capital Asset Pricing Model	10.44%	10.30%
Projected Risk Premium Empirical Capital Asset Pricing Model	12.27%	12.01%
Normalized Risk Premium Analysis Over Utility Bonds	10.80%	10.68%
Projected Risk Premium Analysis Over Utility Bonds	13.26%	13.14%
Analyst Consensus Discounted Cash Flow Model	10.31%	10.04%
Company Guidance Discounted Cash Flow Model	10.50%	9.94%
Comparable Earnings Analysis	11.33%	10.95%
Recommended Cost of Equity Range for Consumers Energy	10.00% - 11.00%	
Recommended Ratemaking Cost of Equity:	10.50%	

Consumers Energy submits that the evidence, on the whole record, supports a conclusion that an authorized ROE of 10.75% will most reasonably balance customer and investor interests, while still accounting for the significant financial impact of the TCJA.

e. Response To Staff’s, The Attorney General’s, ABATE’s, MEC/NRDC/SC/EC/MEIBC’s, And Walmart Stores East, LP And Sam’s East, Inc.’s Additional Arguments

Staff, ABATE, the Attorney General, and Walmart Stores East, LP and Sam’s East, Inc. (collectively “Walmart”) all rely in some manner on the claim that there is a trend toward lower ROEs in recent rate cases nationally to suggest that Consumers Energy’s ratemaking ROE should be reduced. Staff, ABATE, and the Attorney General, in particular, point to recently authorized ROEs for other utilities nationally as reported by Regulatory Research Associates (“RRA”) to argue, essentially, that Consumers Energy’s proposed ROE is out of step with the national trend. However, there are significant problems with relying on such trends as a benchmark for setting ROE rates in the instant case. First, Mr. Maddipati pointed out in his

direct testimony that there is no accurate or complete source for the ROE trends of each United States jurisdiction. 3 TR 433. Mr. Maddipati testified:

“Databases such as Regulatory Research Associates (‘RRA’) attempt to do so but are incomplete. They do not include alternative regulatory jurisdictions (Alabama, Georgia), ROEs set outside of general rate cases (California), cases where ROEs are settled/unstated, and jurisdictions that have separate riders (Wisconsin, Iowa, Virginia), all of which tend to support higher ROE values.” 3 TR 433.

Mr. Maddipati provided a table showing a number of recently authorized ROEs nationally that are supportive of the Company’s requested ROE in this case, but many of which are not reflected in the RRA listing.¹⁴ 3 TR 433-434. Mr. Maddipati’s table is reproduced below:

¹⁴ Several of the approved ROEs listed below are also absent from the listing of recent ROE results provided in Walmart’s Exhibit WAL-3 (originally listed as Exhibit GWT-3).

<u>Company</u>	<u>State</u>	<u>Authorized ROE %</u>	<u>% of Rate Base</u>	<u>Reflected In RRA data?</u>	<u>J.D. Power Customer Impact</u>
Alabama Power	AL	12.94%	100%	No	#2 IOU Nationally
Alabama Gas Company	AL	10.85%	100%	No	
Mobile Gas Service	AL	10.7%	100%	No	
Alliant Energy	IA	11.0% - 12.23%	27%	No	1st Quartile in Midwest
Dominion	VA	10.4% - 11.4%	24%	Yes	
Florida Power & Light	FL	10.55%	100%	Yes	#1 IOU Nationally
Georgia Power	GA	10.95%	100%	No	#3 IOU Nationally
Liberty Utilities	GA	10.00%	100%	No	
MidAmerican	IA	11.70%	42%	No	#1 in Midwest
Pacific Gas & Electric	CA	10.25%	100%	No	
San Diego Gas & Electric	CA	10.20%	100%	No	
Southern California Edison	CA	10.30%	100%	No	
WEC Energy	WI	12.70%	16%	No	1st Quartile in Midwest

The average of these recently awarded ROEs is 11.08% and, as the table shows, many of these utilities are regarded as among the best utilities in the country by customers responding to JD Power surveys. Mr. Maddipati testified that jurisdictions with strong regulatory frameworks have higher customer satisfaction, as well as higher ROEs. 3 TR 434-435. He noted that a 2018 UBS report shows that states with a regulatory environment in the top two quartiles earned ROEs, on average, of 11.9% and 10.3%, respectively, while states in the bottom two quartiles earned ROEs, on average, below 10%. 3 TR 434-435. Staff and intervenor arguments regarding recent ROE trends fail to distinguish between those authorized ROEs granted to companies that have a poor track record of customer satisfaction, and ROEs granted to companies that are leveraging a healthy business to provide customer service that meets or exceeds expectations. In fact, their respective discussions of national ROE trends specifically exclude many of those

constructive utilities' results. Good regulation appropriately reflects the importance of competitive ROEs, which properly provide utilities the tools to provide great customer satisfaction. Instead of aiming for that goal, Staff and intervenor analyses seek to "average down" the Company's ROE by comparing Consumers Energy to companies that have poor performance with their customers and operate in unconstructive regulatory environments.

The RRA data relied upon by Staff, the Attorney General, and ABATE, also includes information demonstrating that the ROE trends reflected in the data are likely not comparable, and hence, not useful in providing any meaningful estimate of an appropriate ROE in this case.¹⁵ Referring to arguments on this topic from ABATE, Mr. Maddipati notes in his rebuttal testimony:

"While Ms. LaConte recognized that limited issue riders are excluded from the RRA average, on pages 17 to 18 of her direct testimony, she goes on to justify the use of this and other RRA exclusions. Her justification demonstrates the very point that I continue to make – capital is finite, and even if a company has not had a general rate case order in the past 10 years, Consumers Energy still has to compete for investment dollars with all of the existing authorized ROEs from other utilities.

"In past cases, Mr. Coppola had continued to point out in his direct testimony that it is important to synchronize the capital structure with the cost of equity. However, the exact same RRA data reference, which I've repeatedly noted is flawed, provides the equity ratio authorized in rate cases and reference as ABATE's Exhibit AB-2, page 10. This same data shows that Consumers Energy's authorized equity ratio is 717 basis points below the first half average for 2018. I also noted in my direct testimony and above that as a result of the TCJA, several jurisdictions have increased equity ratios, and doing so is a tactic noted as a mitigant by both Fitch and Moody's. While witnesses in this case want to

¹⁵ Walmart's listing of recently approved ROEs lacks any information to support a comparison regarding the comparability of the ROE decisions at all. See Exhibit WAL-3 (originally listed as Exhibit GWT-3), which includes no information regarding the listed utilities' capital structure or resulting overall rate of return.

use RRA to suggest that the national average ratemaking ROE is below 10%, they refuse to use the same data set to calibrate for the relative levels of equity – instead they have selectively presented data without context for which these other jurisdictions operate.”
3 TR 503-504

In addition to information about the authorized ROE for each utility in the listing, RRA’s listing also provides data reflecting each utility’s approved common equity ratio and overall rate of return. RRA’s 2018 listing of utility decisions includes the Commission’s March 29, 2018 Order in Case No. U-18322. Exhibit AB-2, page 10. The RRA data lists Consumers Energy’s approved equity ratio from Case No. U-18322 as 40.89% and its overall rate of return at 5.89%. Of the 34 electric rate case decisions listed in Exhibit AB-2 for 2018 so far, Consumers Energy’s equity ratio was the fourth lowest and its overall rate of return was the fifth lowest. That information is significant because the investors’ earnings are actually a function of the ROE and the equity ratio. So, even if a utility’s ROE were to appear higher than ROEs granted to other utilities, investors’ earnings could be lower if, in fact, the equity ratio is comparatively low. The fact that the Company’s overall rate of return compared to other utilities in the RRA report is on the low end of all reported utilities for 2018 so far, indicates that comparing Consumers Energy’s ROE to the other listed utilities is not a fair, or reasonable comparison, even if the information in the RRA report were complete (which it is not).

In Case No. U-17895, the Commission stated that “it declines the invitation to give significant weight to ROE determinations resulting from evidentiary records that are not a part of this proceeding and that are exclusively related to geographically and structurally different utilities.” MPSC Case No. U-17895 September 8, 2016 Order, page 20. Consumers Energy submits that, given the problems with the ROE trend data relied upon by Staff, the Attorney General, ABATE, and Walmart, the Commission should continue to view this type of information skeptically. Instead, the Commission should focus on benchmarking Consumers

Energy's ratemaking ROE to those authorized in states with high customer satisfaction and highly regarded regulatory environments.

Staff, the Attorney General, ABATE, and Walmart also argued that, to the extent the Commission grants the Company's request for an IRM in this case, it should implement a corresponding reduction in the Company's final authorized ROE. Mr. Maddipati offered the following testimony responding to these arguments:

“Staff witness Megginson (pages 36-37), AG witness Coppola (page 55), ABATE witnesses Pollock (pages 2,7 and 8) and LaConte (page 11) each critique the Company's IRM and suggest that the proposed IRM reduces the Company's risk and is therefore not reflected in the Company's ROE, but this logic fails to recognize several critical points:

- “• The Company files its general rate cases using a projected test year and if an IRM is not approved the Company would simply file a general rate case in 2019 seeking recovery of proposed expenditures in 2020 and again in 2020 seeking recovery of proposed expenditures in 2021. The IRM simply eliminates the administrative burden of filing a rate case in 2020 and 2021, but it would not provide rate relief any more frequently or any sooner.

- “• There is no incremental cash flow or liquidity benefit from an IRM, as the Company does not receive rate relief any sooner than if it filed a general rate case. Furthermore, the Company files general rate cases based on a forward looking test year, therefore no capital would be required to be spent prior to receiving a Commission order in a general rate case;

- “• The IRM is subject to a reconciliation and prudence review which would be no different than if the Company had filed for a general rate case. The only difference is that the IRM allows the Company to better plan resources needed to complete work. This planning benefits customers, who will also have better visibility to their rates over an extended period of time. Absent the IRM, the Company would adjust its capital plans (potentially cancelling contracts or ramping resources) based on final rate orders in a potential 2019 and 2020 general rate case. No incremental financial or business risk is reduced

through the proposed IRM. However, capital projects could potentially be more efficiently planned, given the longer lead time provided for by the IRM; and

- “• The IRM may in fact increase risk since it does not provide general rate relief. Revenue as part of the IRM is tied to specific capital programs and to the extent those programs are not completed, no incremental revenue would be received. However, during the IRM period inflationary pressure could potentially increase Operations and Maintenance (‘O&M’) costs, rising short-term interest rates could increase borrowing costs, and easing of accommodative monetary policies could put pressure on long-term borrowing costs and the Company’s ROE. None of these potential increased costs are recoverable via the IRM, and as such, the IRM would subject the Company to increased risk.” 3 TR 536-538.

Mr. Maddipati further testified that recovery mechanisms, like the one proposed in this case, are prevalent among regulated utilities. 3 TR 538. In support, he cited a September 2017 report by RRA, which concluded that: “roughly two-thirds of all utility commissions permit the use of, or are considering the use of, an adjustment clause for new capital investment.” 3 TR 538. Since such mechanisms are common, it would be incorrect to conclude that approving the Company’s proposed IRM in this case would render it comparatively less risky than other utilities. Even if such mechanisms did reduce a utility’s business risk (which they do not), that reduced risk would already be reflected in the pool of comparable utilities and further reduction in the ROE would double-count its effect.

Contrary to the requests of Staff, the Attorney General, and ABATE, it would be inappropriate to reduce the Company’s ROE corresponding to approval of the IRM proposed by the Company in this case. None of the parties’ additional criticisms or arguments opposing the Company’s cost of common equity analysis have merit. The Commission should reject these arguments.

MEC/NRDC/SC/EC/MEIBC witness Jester provided testimony suggesting that the Commission should “consider the availability of specific performance incentives when applying broad performance criteria to the authorized return on equity” 6 TR 2593. He recommends that the Commission should target the Company’s ROE somewhat below the national average but within the “zone of reasonableness” 6 TR 2604-2605. However, it appears that Mr. Jester proposes that his recommendation take effect in the Company’s next electric rate case, rather than in this case. He states:

“Because a specific system of evaluating relative performance of a utility should be done with care and broad stakeholder involvement, I do not recommend making this change in practice in the present case. Rather, in this case, the Commission should initiate a stakeholder process following on from its preparation of the PBR [Performance Based Ratemaking] Report to facilitate its adoption of such criteria in the Company’s next general rate case.” 6 TR 2596.

Mr. Maddipati responded in rebuttal that Mr. Jester’s testimony includes a number of general considerations and factors as it relates to potential performance-based ratemaking but does not appear to contain any clear or firm recommendations on which the Commission could act. 3 TR 560. Furthermore, Mr. Maddipati testified:

“As I previously noted, the Company was part of the Commissions workgroup on performance based ratemaking and continues to be interested in exploring potential innovative alternatives to traditional ratemaking that can benefit customers and shareowners. In the Commission’s report on PBR it noted:

“Such transformative changes would not be made **to the entire regulatory paradigm overnight**; the Commission is more inclined to test the efficacy of PBR through specific natural gas and electric utility pilot programs or other targeted opportunities. This study has demonstrated that **incorporation of a public process with stakeholders and utilities is important** to the success of new and innovative programs.’ *MPSC Report on the Study of Performance-Based Regulation*, page 24.

“As noted in the Commission’s report, potential pilots or target opportunities may be appropriate but Mr. Jester’s suggestion that broad sweeping changes be made in the Company’s next general rate case is not appropriate. The Commission regulates a number of regulated utilities, not just Consumers Energy, and any potential PBR should include all stakeholders. A single utility’s general rate case is not the appropriate venue for such a discussion.” 3 TR 560-561 (emphasis added in testimony).

Mr. Maddipati also notes a number of concerns regarding the manner of implementation proposed by Mr. Jester in future cases. 3 TR 561-563. Mr. Jester’s proposals appear to give no consideration to the *Hope* and *Bluefield* requirements for a constitutionally sufficient ROE and offer no substantive analysis for determining the appropriate ROE. His recommendation for a stakeholder process in a general rate case is inconsistent with the Commission’s stated plan for future evaluations regarding performance-based ratemaking initiatives and is not well-considered as an input to future ROE determinations. Mr. Jester’s proposal should be rejected.

Finally, Walmart witness Gregory W. Tillman proposed that the Commission should consider the inclusion of Construction Work in Progress (“CWIP”) in rate base as a risk-reducing feature of Consumers Energy’s regulatory environment. 7 TR 3343-3344. Although Mr. Tillman does not state so explicitly in his testimony, Consumers Energy understands his recommendation to suggest that the Commission should reduce the Company’s ROE by some degree, as a result of the Commission’s decision to include CWIP in rate base. To the extent that this is Walmart’s recommendation, Consumers Energy submits that it should be rejected. As Mr. Tillman himself notes, “the Commission has long allowed utilities in Michigan to include CWIP in rate base” (7 TR 3343), hence any risk-reducing attributes of this practice are already incorporated into the Company’s existing ratemaking ROE. Walmart included the same recommendation in the Company’s last electric rate case, Case No. U-18322; however, the

Commission did not include any discussion in its Final Order in Case No. U-18322 adopting Walmart's proposal. The Commission should decline to do so in this case as well.

f. ROE Conclusion And Request For Relief

For reasons addressed above, and in the evidentiary presentation of Company witness Maddipati, Consumers Energy submits that the evidence in this case, taking into account the financial impacts of the TCJA, supports setting a ratemaking ROE of 10.75% rather than decreasing from its current level of 10.00% to 9.75% or below as proposed by Staff, the Attorney General, and ABATE. Any reduction below the Company's current 10.00% ROE would be particularly unreasonable given current economic and financial conditions, the uncertainty and volatility in the capital markets as a result of activity by the Federal Reserve, and the need for Consumers Energy to raise substantial amounts of funding for planned investments in Michigan.

Authorizing an ROE in this case of 10.75% for Consumers Energy, in combination with the capital structure and cost rates for other components as proposed by Consumers Energy, results in an overall after-tax rate of return of 6.28% as compared to the 5.81% overall rate of return calculated by Staff using a 9.75% return. The calculation of the 6.28% overall rate of return is shown in Appendix F, page 1.

2. Long-Term Debt Cost

The Company originally proposed a long-term debt cost rate of 4.60% in this case which was based, in part, on the Company's projected 4.90% interest rate on an expected \$400 million new debt issuance in May 2018 and \$700 million in August 2018, as well as a 5.40% interest rate on an expected \$300 million in February 2019 and \$1,275 million in August 2019. 4 TR 821, 832-833; Exhibit A-14 (AJD-4), Schedule D-2; Exhibit A-14 (AJD-1), Schedule D-1, line 2, column (e). The Company also assumed a spread of 140 basis points over the United States Treasury rate. 4 TR 833.

Staff utilized the actual cost rate of 4.05% for the Company's May 2018 debt issuance and forecasted a 4.50% cost rate for the August 2018 debt issuance, and 4.80% for the February and August 2019 debt issuances using updated Value Line estimates and added a spread of 100 basis points. 6 TR 2500. This results in a reduced long-term debt cost rate of 4.47%. Exhibit S-4, Schedule D-1. While Company witness Denato explained that the impact of tax reform may necessitate a bond spread assumption of 140 basis points (at a minimum), rather than the 100 basis points used by Staff if either the ROE or Equity Ratio are approved at levels lower than that requested in this case, the Company accepts Staff's projection, as it is based on the most recent issuance.

3. Short-Term Debt Cost

The Company calculated its short-term debt cost rate of 4.16% by dividing the total cost of the two components of short-term debt (i.e., the costs related to: (i) its revolver/commercial paper facilities, and (ii) its renewable liabilities program) by the total outstanding balance projected for the two components. 4 TR 835-836; Exhibit A-14 (AJD-5), Schedule D-3, page 1. The cost of the Company's revolver/commercial paper component of short-term debt was calculated by applying a projected London Interbank Offered Rate ("LIBOR") rate and spread to the Company's forecast of its outstanding average short-term borrowing under its commercial paper facility, and adding the cost of certain expected and customary fees associated with maintaining the Company's short-term credit facilities. 4 TR 836-837; Exhibit A-14 (AJD-5), Schedule D-3, page 2. The cost of the Company's Renewable Liabilities Program was also based on the LIBOR rate and spread for the Commercial Paper Program, which represents the "average short-term borrowing rate" available to Consumers Energy consistent with the requirements of MCL 460.1049(4).

The Attorney General Agrees with the Company's short-term debt cost rate. See Exhibit AG-26.

Staff recommends a cost of short-term debt of 3.35%, as reflected in Staff's Exhibit S-4, Schedule D-1. As discussed by Mr. Denato in his rebuttal testimony, the short-term debt balance is comprised of two components. The first component is short-term debt – revolver/commercial paper. The second component is short-term debt – renewable liability. 4 TR 861. The Company does not dispute Staff's short-term debt – revolver/commercial paper of \$5.16 million, as Staff's projection uses updated LIBOR forecast projections and is comparable to the Company's calculation. However, while Staff witness Megginson recognized the full amount of the Company's projected short-term debt – renewable liability balance, he assigned no cost to that balance, which was in error. 4 TR 861-862. As discussed by Mr. Denato in his rebuttal testimony, he calculated a \$1.2 million cost for the short-term debt – renewable liability. 4 TR 861. This is proper because the inclusion of the cost related to the Company's renewable liability in short-term debt is based on a long-standing practice and is authorized by legislation. Section 21(4) of Public Act 295 of 2008 discusses the cost rate for 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." 4 TR 862. This cost has also been recognized and approved by the Commission, most recently in Case No. U-18322. 4 TR 862. A departure from this practice is unsupported and without merit. See Exhibit A-147 (ADJ-12) and A-148 (AJD-13), which are Staff's Exhibit A-4, Schedule D-1, updated for the change to the cost of short-term debt and other changes, including common

equity balance and common equity cost rate.¹⁶ 4 TR 863. As demonstrated in Exhibit A-147 (ADJ-12) and A-148 (ADJ-13), if Staff's projected cost of short-term debt is increased \$1.2 million from \$5.16 million to \$6.36 million, the resulting calculations demonstrate a cost of short-term debt of 4.14% - an amount very close to that of the Company (4.16%). 4 TR 863.

4. Other Cost Rates

The Company and Staff are in agreement that the cost rate for preferred stock should be 4.50% (*see* Exhibit A-147 (AJD-12) and Exhibit A-14 (AJD-1), Schedule D-1), the cost rates for the long-term debt, preferred stock, and common equity components of JDITC should correspond to the cost rates established for long-term debt, preferred stock, and common equity, and the cost rates for other components should be zero. Exhibit A-14 (AJD-1), Schedule D-1, and Exhibit S-4, Schedule D-1. Attorney General witness Coppola explicitly agreed in this testimony that 4.50% was the correct cost rate that should be applied to preferred stock. 6 TR 2842. The cost rate proposed by the Company, and agreed to by Staff and the Attorney General, of 4.50% should be applied.

D. Overall Rate Of Return

Using an ROE of 10.75% in the capital structure, in combination with the cost rates for the other components recommended by the Company at the conclusion of its rebuttal testimony, results in an after-tax cost of capital of 6.28% and a pre-tax weighted cost of capital of 7.82%. The capital structure, cost rates, and calculation of these returns are shown in Exhibit A-147 (AJD-12) and reproduced in Appendix F, page 1. Consumers Energy requests the Commission adopt the capital structure and cost rates as shown in Appendix F, page 1 to this Initial Brief.

¹⁶ The effect of Staff's adjustments for common equity balance and short-term debt rate result in an increase in the weighted cost ratemaking capital. Thus, if a 10.50% ROE is used, the overall cost of capital increases from 5.81% to 6.18 %, as shown on Exhibit A-148 (ADJ-13).

V. ADJUSTED NET OPERATING INCOME

A. Jurisdictional Revenues And Sales Forecast

1. Sales Forecast

a. Company Position

Company witness Eugène M.J.A. Breuring presented the Company's projected jurisdictional electric deliveries for the test year ending December 31, 2019. Mr. Breuring initially testified that the Company has projected its jurisdictional electric deliveries for the test year to be 37,110 GWh. Exhibit A-15 (EMB-3), Schedule E-2. This projection was developed by employing the detailed analytical methodology described in Mr. Breuring's testimony. See 5 TR 1751-1758. Full service and Retail Open Access ("ROA") customers are represented in the forecast.

The key variables affecting the Company's forecasts are weather, the economy, and demographics. 5 TR 1751. The 15-year average of Heating Degree Days and Cooling Degree Days are used to capture the seasonal variation of weather in deliveries and demand across the year. 5 TR 1751. In developing the long-term customer forecast, IHS Markit's ("IHS") population projections are used. 5 TR 1751. As an indicator to capture the economy's growth expectations, the Company uses IHS' employment and industrial production forecasts. 5 TR 1751.

The Company's total generation requirements were also supported by Mr. Breuring. Mr. Breuring testified that: "[p]er the 2015 System Loss Study, the forecasted total electric deliveries are increased by a line loss factor of 7.45% to determine the Company's total generation requirements, i.e., system output." 5 TR 1758. This can be seen in the system output identified in Exhibits A-15 (EMB-2), Schedule E-1, and A-15 (EMB-5), Schedule E-4.

Additionally, the Company's forecast reflects Smart Energy and Energy Waste Reduction ("EWR") Program savings. Company witness Theodore A. Ykimoff supported the historical and test year energy savings resulting from the Company's EWR programs. See 5 TR 2185-2187. The peak demand forecast is reduced by approximately 101 MW in 2018, and increasing to 394 MW by 2022 for the Company's AC Peak Cycling and Peak Time-of-Use ("TOU") programs. 5 TR 1759. The EWR Program is projected to reduce peak demand by 465 MW in 2018 and 521 MW in 2019, and produce cumulative reductions of 666 MW by 2022. 5 TR 1760.

The Company's total electric deliveries are expected to increase by 0.4 % per year from 2017 to the 2019 test year. 5 TR 1757. The rate category level results are shown in Exhibit A-15 (EMB-4), Schedule E-3. The annual class level results for 2013 through 2022 are shown in Exhibits A-5 (EMB-1), Schedule E-1, and A-15 (EMB-2), Schedule E-1.

In rebuttal, Mr. Breuring agreed with the Cities of Grand Rapids' and Flint's position that the sales forecast should be adjusted to incorporate the Company's proposed LED streetlighting conversions. 5 TR 1763. This change results in reducing the originally filed annual jurisdictional deliveries total by 6,107 MWh. 5 TR 1763-1764.

b. Response To Energy Michigan

Energy Michigan witness Alexander J. Zakem contended that the projected losses to the Company's ROA customers shown in Exhibit A-15 (EMB-2), Schedule E-1, do not reflect recent history of these losses, and recommended that the forecasted loss percentages in that exhibit be changed to reflect recent history. 7 TR 3152-3157. Mr. Breuring explained that such a change is not necessary and would have no impact on the rest of the Company's presentation. The line loss projections in Exhibit A-15 (EMB-2), Schedule E-1, are provided for informational purposes and are based on the 2015 line loss study. 5 TR 1765. The Company's COSS in this case uses

the 2016 line loss study presented by Company witness Anderson (see Revised Exhibit A-29 (JRA-14)), and does not use the line loss projections in Exhibit A-15 (EMB-2), Schedule E-1. 5 TR 1765.

2. Total Electric Operating Revenues

Mr. Breuring also presented the Company's analysis of projected test year total electric operating revenues, which includes Base Tariff Revenues, Power Supply Cost Recovery ("PSCR") Revenues, and Miscellaneous Revenues. Mr. Breuring initially testified that the Company has projected its total electric jurisdictional operating revenue for the projected test year to be \$4.309 billion. Exhibit A-15 (EMB-3), Schedule E-2, line 28, column (k). This amount was adjusted to \$4.312 billion after including the expenses and revenue from various job work activities. Exhibit A-15 (EMB-3), Schedule E-2, line 32, column (k).

The Company developed its present revenue calculation by making adjustments to 2017 actual deliveries and revenues. Exhibit A-15 (EMB-3), Schedule E-2, summarizes the component differences between the 2017 historic revenues and the forecasted test year revenues. Mr. Breuring described the adjustments made to 2017 historical actual deliveries and revenues for the purpose of developing the projected test year deliveries and revenues. See 5 TR 1755-1758.

Additionally, the Company's projected present revenues proposal includes customer participation projections for the Residential Senior Citizen ("RSC") and Residential Income-Assistance ("RIA") provisions. 5 TR 1750. Mr. Breuring indicated that the average test year customer count projections for the RSC and RIA provisions are 343,200 and 56,800, respectively. 5 TR 1750. These RSC and RIA provision customer counts translate into \$14.4 million of credit revenues for the RSC provision, and \$4.8 million of credit revenues for the RIA provision. 5 TR 1750.

As discussed, Mr. Breuring agreed in rebuttal that the sales forecast should be adjusted to incorporate the proposed LED streetlighting conversions. This adjustment results in a corresponding decrease in base tariff revenues in the amount of \$1.388 million. 5 TR 1763-1764. Mr. Breuring also agreed in rebuttal with Staff witness Isakson's recommended adjustments to revenue related to the Commission's Errata Order and Rehearing Order issued in Case No. U-18322. This adjustment results in increasing revenues by \$3.9 million. 5 TR 1764. Taking into account these adjustments, the test year jurisdictional total revenue amount is \$4.325 billion (before accounting for job work expense). See Appendix C, page 1, line 4, column (e).

B. Fuel, Purchased, And Interchange Power Expense

Company witness Richard T. Blumenstock, Executive Director of Electric Supply, testified concerning the Company's projected fuel, purchased, and interchange power expense. See 5 TR 1434-1439; Exhibit A-33 (RTB-1). Mr. Blumenstock explained that the Company projected these power expenses using production cost simulations. 5 TR 1435. The Company uses the PROMOD IV Program, developed by ABB, to prepare these simulations. 5 TR 1435. This program "performs production cost simulations of the Company's generating resources, purchased power resources, and interchange power resources to meet projected customer electric demand requirements." 5 TR 1435. The Company is forecasting \$883,958,000 of Total Fuel, Variable Purchased and Net Interchange expense and \$710,811,000 of Total Capacity and Non-Utility Generator Fixed Costs. Exhibit A-33 (RTB-1), page 1, line 26, column (o) and line 33, column (o), respectively. These amounts, together with the test period transmission expense of \$439,642,000 (Exhibit A-33 (RTB-1), page 1, line 34); the MISO Schedule 2 (Reactive) credit of \$4,500,000 (Exhibit A-34 (RTB-2), page 1, line 36); and the reagent expenses for pollution control equipment that are expected to be recovered as part of the Company's power supply costs

in its PSCR proceedings (Exhibit A-33 (RTB-1), page 1, lines 35, 37 through 39) constitute the total power supply costs for the test year of \$2,044,146. Exhibit A-33 (RTB-1), page 1, line 40. After adding in intersystem sales revenue, the total projected power supply cost for the test year is \$2,124,368,000. Exhibit A-58 (EMB-6). No other party contested this total electric amount, and Staff accepted the Company's calculation of this expense. See Exhibit S-3, Schedule C-1, line 5, column (e).

The total fuel, purchased, and interchange power expense amount has been jurisdictionalized to reflect the amount to be included in the calculation of the Company's rates for the test period. See Exhibit A-58 (EMB-6). The Company has included this jurisdictionalized amount in Appendix C, page 1, line 5, column (e). Staff provided its proposed jurisdictional amount in Exhibit S-3, Schedule C-1, line 5, column (f).

C. Other O&M Expense

1. Distribution And Energy Supply O&M Expense

a. Company's Position

Company witnesses Bordine and Anderson testified concerning Consumers Energy's Electric Distribution O&M expense projections. Exhibit A-46 (AJB-13) provides a summary of actual and projected electric and common O&M expenses for the LVD and HVD systems. 4 TR 1245. The Company projects the Electric Distribution O&M expenses to be \$166,514,000 for 2018 and \$177,723,000 for the 12 months ending December 31, 2019. Exhibit A-46 (AJB-13). The projected test year expenses consist of \$195,219,000 for the Electric Division; with a \$17,496,000 reduction due to the Smart Energy Direct O&M benefits. 4 TR 1246; Exhibit A-46 (AJB-13), page 1.

The majority of the O&M expenses included in Exhibit A-46 (AJB-13) are for the Electric Division, and the expenses represent activities associated with: (i) O&M Associated

with Construction; (ii) Reliability; (iii) Operations, Maintenance, and Metering; (iv) Field Operations Services; (v) Smart Energy Operations Center; (vi) Grid Management; (vii) Planning and Scheduling; (viii) Operations Performance; (ix) Operations Management; (x) Accruals Injuries and Damages; (xi) Accruals – Employee Incentive Compensation Plan (“EICP”); (xii) IT Projects; (xiii) Electric Operations; and (xiv) Electric Engineering. Exhibit A-51 (AJB-18). No party contested the Company’s proposed Electric Distribution O&M expenses. However, as addressed in more detail below, RCG witness Peloquin proposed a Forestry expense, otherwise known as a Line Clearing expense, tracking mechanism.

b. Response To RCG

Mr. Peloquin asserted that Consumers Energy perennially underspends rate case authorized O&M amounts for Line Clearing work. However, this is incorrect. Mr. Bordine explained that the authorized amount for Line Clearing in Case No. U-17990 was \$48.5 million and in Case No. U-20134 was \$51.8 million, totaling \$100.3 million over the time period of 2016 through 2017. 4 TR 1307-1308. For the same time period 2016 through 2017, Consumers Energy actually spent \$100.5 million. Therefore, the Company is spending Line Clearing amounts that are consistent with the authorized amounts.

Mr. Peloquin further proposes a Line Clearing expenses mechanism in this case. Such a mechanism is unnecessary because the Company’s Forestry Operations staff meets semi-annually with Staff to review spending levels, miles cleared, and other metrics of performance. 4 TR 1308. The Company also informally reports Line Clearing expense and miles completed to Staff on a monthly basis. 4 TR 1308. Mr. Bordine explained that these processes provide feedback to both Consumers Energy and Staff, and is designed to highlight issues in a timely manner and address these concerns. 4 TR 1308. The Company submits that

the current process in place with Staff is sufficient and provides greater value than the financial tracking mechanism proposed in this case.

2. Fossil And Hydro Generation O&M Expense

a. Company's Position

Company witness Broschak supported Consumers Energy's Fossil and Hydro Generation O&M expenses. The Company has consistently and effectively managed these expenses. In the 2013, 2014, and 2015 Non-Fuel O&M Benchmark Studies, the Company's Non-Fuel O&M for its coal plants was in the top 25% (lowest cost) in the nation; in 2011 and 2016, the Company's Non-Fuel O&M was in the top 50% in the nation. 7 TR 3251, 3264. As the Company has reduced its use of coal-fired power plants, increased generation from gas-fired power plants, and experienced increased O&M costs associated with environmental control equipment, Consumers Energy has been challenged to continue to keep costs low. However, Consumers Energy continues to manage its Fossil and Hydro O&M costs by making decisions that are in the customers' best interest and that keep the Company competitive in the market. 7 TR 3251.

Company witness Broschak described how the expense items that comprise the overall portfolio of Fossil and Hydro Generation-related O&M expense were developed for the test year. 7 TR 3229-3231. Exhibit A-62 (JPB-5) summarizes the Company's projected Fossil and Hydro Generation O&M expenses. For the test year, Mr. Broschak projected a total Fossil and Hydro Generation O&M expense amount of \$169,090,000. 7 TR 3229; Exhibit A-62 (JPB-5).

Exhibit A-62 (JPB-5) separates the Company's Base O&M and Adjusted O&M expenses, with the Adjusted O&M expense comprised of Environmental Operations and Major Maintenance expenses. Mr. Broschak explained that Base O&M includes labor and non-labor components. Labor is the primary cost and has a predictable, stable rate of increase; non-labor costs also increase at a predictable rate, and include: (i) fuel (diesel and gasoline) for equipment

and vehicles; (ii) material; (iii) tools; (iv) cleaning supplies; (v) facilities; (vi) security; and (vii) road and grounds maintenance. With respect to Major Maintenance costs, the Company projects that it will spend \$48.996 million during the test year. 7 TR 3233. In support of its Major Maintenance expenses, Mr. Broschak provided testimony regarding: (i) the specific plants that the Company expects to require Major Maintenance projects during the test year; (ii) the amount and distribution of those costs across the Company's plants; (iii) the reasons the Company will incur those expenses; (iv) the factors that contribute to differences in Major Maintenance costs from one generating unit to the next; (v) the categories of Major Maintenance projects; (vi) the nature of the work involved in each category of Major Maintenance projects; and (vii) benchmarks for demonstrating that the Company is effectively managing its maintenance costs. 7 TR 3234-3246, 3250-3251. Due to the number of factors involved, 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. Factors such as weather, equipment and labor availability, and electrical system stability can affect the actual timing of an outage and maintenance spending. 7 TR 3234-3235. Environmental Operations expenses include labor and material costs for operation of the AQCS at the Karn and Campbell sites. 7 TR 3232.

The requested O&M expenses are necessary and reasonable to continue Consumers Energy's successful operation of the generation fleet.

b. Response To MEC/NRDC/SC

MEC/NRDC/SC witness Comings contended that: "[w]hen viewed on a plant or unit basis, non-fuel O&M costs per [MWh] for Karn Units 1 and 2 are higher than the majority of coal units in the United States." 6 TR 2709. Mr. Broschak agreed that: "Karn Units 1 and 2 are

the least economic units on a Non-Fuel O&M/MWh basis of the Company's coal units." 7 TR 3263. Nonetheless, Karn Units 1 and 2 continue to provide customer value. For example, from 2014 through 2017, the Net Energy Value ("NEV") for Karn Unit 1 was \$34,814,413 and the NEV for Karn Unit 2 was \$37,622,391. 7 TR 3265; Exhibit A-60 (JPB-2). NEV is the difference between the market value of energy and the cost of producing and supplying that energy, and indicates a measure of value that the generating units provide to customers. 7 TR 3265. Positive NEV results when a unit is operating and the market pricing exceeds the cost of production for that unit and reflects a direct reduction to customer costs. 7 TR 3195-3196. The positive NEV at Karn Units 1 and 2 indicates that the units continue to provide value to the Company's customers, and the Company will continue to evaluate its investments in these units to optimize customer value and provide for the safe and reliable operation of the units until they are retired. 7 TR 3265.

3. Facilities O&M Expense

Company witness Saba supported the Company's actual and projected Electric Operations Support O&M expenses related to Facilities, Real Estate, and Administrative Operations. Fleet Services are addressed by Company witness Straub. 5 TR 2138.

Ms. Saba provided Exhibit A-92 (LDJ-2), which provided the Company's projected Electric Operations Support O&M expenditures. As Ms. Saba explained, facilities work "includes items such as maintenance and repair of heating, AC, 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." 5 TR 2141. Real estate services includes: "the lease costs associated with corporate facilities, records management and land inventory systems, property rights research and investigation, costs for land transactions, and the cost of land management and maintenance activities required to closely monitor

encroachments and uses of Company property and easement rights to ensure system integrity and safeguard the public.” 5 TR 2141. Finally, Ms. Saba explained that administrative operations, “assists with administration support services for Consumers Energy’s Security Command Center, IT, Help Desk, Human Resources, Corporate Safety and Health, Fleet, Facilities, Supply Chain, Learning and Development, Real Estate, Travel Services, Operating Maintenance and Construction Jobline, and its Mail services.” 5 TR 2141-2142.

Based on these projects, Ms. Saba explained that the Company is projecting total Electric Operations Support O&M expenditures to be \$14,697,000 for the test year 12 months ending December 31, 2019, as shown on Exhibit A-92 (LDJ-2), line 4, column (d).

No party to this proceeding contested any of the Company’s projected Electric Business Services O&M expenditures in the record.

4. Fleet Services O&M Expense

Company witness Straub provided the Company’s Fleet Services O&M expenses for the 2017, 2018, and the 12 months ending June 30, 2019. 5 TR 1517; Exhibit A-113 (BKS-3).

Mr. Straub explained what is included in Fleet Services O&M as follows:

“Fleet Services operations include O&M for Corporate Services. Fleet Service costs in total are captured as ‘responsibility’ dollars then allocated or loaded to the business. Every work order that is completed using Fleet Services is ‘loaded’ for fleet costs. The loading baseline is labor and then a percentage of cost is added to the work order and cleared from the fleet cost centers. This is consistent throughout operational work orders. Those costs are not captured in my testimony because they 1 reside in operational O&M and capital costs.” 5 TR 1517-1518.

Mr. Straub explained that the portion of O&M expense included in Exhibit A-113 (BKS-3) is the corporate direct charges. 5 TR 1518. The \$182,000 in O&M expense identified in Exhibit A-113 (BKS-3) contains Fleet Services costs charged to Corporate Services for maintenance, repairs, fuel, and depreciation for vehicles assigned to corporate departments and corporate

employees. 5 TR 1518. Mr. Straub further explained that the test year Fleet Services O&M expense was derived by using the Company's 2019 planning outlook. 5 TR 1518. No party in this case contested the Company's projected O&M expense for Fleet Services.

5. Customer Experience O&M Expense

Company witness Miller provided a detailed description of the Company's Customer Experience Department, which is responsible for customer research, marketing, experience design, digital operations, payment programs, and management and operations of the Company's Product Portfolio, including for residential and C&I customers. 5 TR 1785-1814. As originally filed, Consumers Energy's test year costs for the Customer Experience Department, including incremental costs to support a new residential Summer on-peak and all-other-hours rate ("Summer On Peak Rate"), were \$26,499,000. 5 TR 1785; Exhibit A-106 (HWM-2), page 1, line 1. In its rebuttal case (as explained below), the Company reduced this amount by \$2,235,000.

The Commission should approve the Company's test year O&M for the Customer Experience Department. Customer Experience plays an import role in delivering service to customers, as Mr. Miller explained:

"Marketing is responsible for developing the Company's understanding of customers (residential and business) and guiding actions that will deliver more valuable services and relevant communications. Specific insight activities include, but are not limited to, conducting primary customer research, analyzing primary and secondary customer data, and analyzing third-party utility studies. The insights from these activities are necessary to develop multi-channel customer engagement strategies and to be more proactive in serving the unique needs of different customers. Additional responsibilities of this department include improving accuracy of customer data through standardized data quality processes. It is important for the Company to have accurate information about its customers such as customer name, service address, mailing address, contact information, associated accounts identified, etc. These are critical pieces of information which

enable the Company to reach its customers and to collect their feedback. The feedback allows us to improve service, program offerings, and customer experience when contacting the company. Data quality is a critical component to both customer and utility safety. For example, in the event of a downed wire, it is critical that the Company has accurate information in the system to quickly and efficiently locate the downed wire. All of these activities are used to guide Company operations, to improve processes, to develop effective communications, and to inform product and service development – all of which improve customer value. Costs for the test year for this program of \$7,770,400 are included on Exhibit A-106 (HWM-2), page 2, line 14.” 5 TR 1786-1787.

The only challenge to Customer Experience O&M came from Staff witness Fromm, who proposed to disallow \$3,403,000 in Marketing and Strategy costs. 6 TR 2424; Exhibit S-9.2, line 6. The Commission should not adopt Ms. Fromm’s position. Mr. Miller testified to the key impacts within Customer Experience and Operations as a result of implementing the Summer On Peak Rate:

“Q. What impacts are expected within Customer Experience and Operations as a result of implementing the Residential Summer On-Peak Rate?

“A. Although gaining customer support and acceptance to make a change is difficult, gaining customer support and acceptance to make a change that customers perceive as forced is almost impossible. On a project of this magnitude, the Company cannot merely focus its attention on the technical requirements necessary to transition all residential customers to a time-of-use rate. It is equally important for the Company to study, test, and design a unique customer experience to assist customers with making the transition. That is, ignoring or paying little attention to how customers perceive the experience will influence the success of the project and will ultimately make it much more difficult and painful for everyone involved. The Company learned this lesson while installing its smart meter infrastructure. It found that having proactive, frequent, and detailed communications with customers around the specific project or initiative being implemented increases their support and adoption of

a change. For instance, the Company developed a specific customer experience plan focused on addressing customer concerns and impacts around the installation of Smart Meters in 2014 and 2015. This was feasible because the Company invested time and resources in developing effective communication plans and processes based on its research and testing of best practices and customer feedback regarding the frequency, language, format, and channel of communication customers preferred. Likewise, the Company used the findings of this research to inform its operational decisions around customer opt-out, community outreach, digital support, and call center support. The result was high communication recall and a 75% increase in customer support, as measured by the Net Promoter Scores. In addition, the Company saw 20% fewer customer complaints regarding the installation of the meters in areas where it provided customers with timely, frequent information. Although this project differs from installing smart meters, the Customer Experience and Operations organization is proposing to leverage the learnings of the latter to help educate residential customers on the benefit of the rate change and to inform them of options to manage their energy use and bills. A successful approach will require strong customer understanding and proactive outreach similar to that described in a 2016 McKinsey report.⁵

⁵ <https://www.mckinsey.de/files/customer-experience-compendium-2016.pdf> 5 TR 1809-1810.

Ms. Fromm based her proposed disallowance on her view that \$3.403 million was attributable to the cost to transition customers to the new Summer On Peak Rate required by the Commission's March 29, 2018 Order in Case No U-18322, page 106, which she equated to implementing a price change to existing rates, and thus the cost was unnecessary. 6 TR 2425-2426. She opined that customers will be indifferent to switching from their current inverted tier rate structure to the Summer On Peak Rate's TOU structure, since the Company has filed annual electric cases to update the prices it charges as part of reflecting its increased

investments. *Id.* Mr. Miller explained why, based on the Company's own work with focus groups regarding the Summer On Peak Rate transition, Ms. Fromm's assumption was not valid:

“Q. Please explain why the Company does not believe customers will view the transition to a summer time-of-use rate as merely a price change.

“A. In September 2018, the Company reached out to its customers through six focus groups to evaluate how they would perceive the move to the new Summer On-Peak Rate. As part of the evaluation, we first informed them that the Company would be implementing a Summer On-Peak Rate without describing why customers were being asked to switch to a time-of-use rate structure. Overall the customers indicated they were confused and frustrated that no information was shared with them explaining why they had to switch rates and the impact to them. This led some customers to question the trustworthiness of the Company's actions and the value of the rate structure change. After gathering this feedback, the Company then provided these customers with details on the structure of the new Summer On-Peak Rate and how the change would impact their monthly electricity bills. Most customers then indicated they understood the reason for the change and were amenable to the new structure. 5 TR 1823-1824.

As a result of this experience, the Company must proactively communicate with customers to explain why the change is occurring and how they can benefit.

As Mr. Miller explained, most customer focus group participants indicated that they wanted six month's advance notice of the transition to the new TOU rate structure, with more than half wanting the communication to begin a year in advance. 5 TR 1824 Otherwise they felt like the Company was not informing them of its true intent. Customers also provided feedback that communicating change is important. For instance, as reflected on Exhibit A-160 (HWM-3), 20% of customer satisfaction with communications in the JD Power customer satisfaction survey is driven by a utility's "effort to communicate changes." 5 TR 1824. Thus, the transition to the Summer On Peak Rates is much more than a mere price increase, and proactive marketing is a

key element in avoiding confusion and frustration, gaining customer trust, and ultimately helping customers to understand how they might benefit under the new rate.

Mr. Miller testified that the Company must invest in segmentation research as part of informing customers about the transition to the new rate structure. The Company must understand how customers use energy, the communication channels they prefer for receiving information (email, radio, print, online, etc.), and the frequency of communications. 5 TR 1824. As Mr. Miller explained, “a senior citizen will have a different perception and response to this change than a young single parent with children at home during the summer. Similarly, the message that resonates best with a family who associates with being ‘green’ will be quite different than that of family who may be struggling financially to pay their monthly energy bills.” 5 TR 1824-1825. The use of different communication messages and channels, when done effectively, can reduce incremental customer complaints and calls resulting from questions and concerns over the rate change.”

The Company must also invest in data analytics as part of its strategy to proactively address customer concerns from this transition. Mr. Miller explained:

“Investing in the tools and resources to analyze customer electric usage behavior is important for tailoring the Company’s messages to inform customers of the projected bill impacts from this transition. As mentioned earlier, customers were more amenable to the change once they understood how it would impact them individually. In addition, the Company will also use this information to identify customers who are likely to experience a substantial increase as a result of moving to a time-of-use rate structure along with potential solutions to help them manage their bills, such as budget billing or billing and usage alerts.” 5 TR 1825.

Mr. Miller went on to explain that another utility (Toronto Hydro) successfully implemented a new TOU rate structure based on a communications strategy similar to that proposed by

Consumers Energy that proactively identified multiple touchpoints to frequently engage customers through an active dialog. 5 TR 1825.

Consumers Energy defines a successful communications strategy as one that results in high customer awareness, satisfaction, and no formal complaints. Mr. Miller described two different utility communications strategies, each with different results:

“For instance, 98% of Toronto Hydro’s residential customers were aware of the change and 73% of them felt the utility was helping prepare them for the switch to a summer time-of-use rate. Conversely, Puget Sound and United Illuminating used a more traditional approach to communicating with customers about the transition to time-of-use rates and saw increased customer complaints to their regulators, which eventually lead to them canceling their time-of-use programs. Some additional findings associated with the communication strategies employed by the three utilities mentioned above are included in Exhibit A-161 (HWM-4). These findings were gathered for the Company by consultants with experience in implementing time-of-use rates in California.” 5 TR 1826.

Indeed, when RCG witness Peloquin (7 TR 3181) made the unsubstantiated claim that a large rejection of the new Summer On Peak Rate would occur, with thousands of customers requesting to convert to non-transmitting meters to remain on the current inverted block rate, Mr. Miller emphasized that with the right preparation and education, customers will accept the new Residential Summer On Peak rate (5 TR 1587).

Mr. Miller’s rebuttal testimony (5 TR 1826) noted that, based on Staff witness Isakson’s acceptance of the Company’s revised plan to transition customers to the proposed Summer On Peak Rate (6 TR 2352), the Company had revised its communication strategy. An extended implementation timeframe would provide Consumers Energy more time to develop and refine its communication strategy, and as a result, fewer test year communication expenses associated with transitioning customers to the new Summer On Peak Rate. The Company, therefore, projects it

will need \$3,037,000 over three years, with \$1,168,000 required in 2019, to perform the required customer analysis and outreach efforts associated with the revised plan. This represents a \$2,235,000 reduction in test year O&M expenses requested by the Company in this proceeding. 5 TR 1826. The Company included the lower expenses in the updated revenue requirement admitted as Exhibit A-167 (HJM-70).

As a result of the forgoing, the Commission should not adopt Staff's proposed disallowance of \$3,403,000 in Marketing and Strategy costs, which was based on Staff's position transitioning 1.6 million customers to a new rate structure would be equivalent to implementing a price change to existing rates. As Mr. Miller's testimony established, the transition clearly requires much more. The Commission should, therefore, approve the entire amount of the Company's \$26,499,000, in test year O&M for the Customer Experience Department, minus \$2,235,000 as discussed above.

6. Customer Payment Program O&M Expense

a. Company's Position

Mr. Miller also testified in support of Customer Payment O&M expenses. He testified that Customer Payment programs encompass the design, O&M, and reconciliation processes associated with all methods of payment available for customers. 5 TR 1791. This includes the Company's new payment portfolio, which provides customers with consistent policies across payment channels (online, Interactive Voice Response, live agent, payment offices, and third-party locations) and across payment options (mailing a check, automatic bank account withdraw, one time or recurring credit or debit card, and cash payments). 5 TR 1791-1792. The Company's test year costs for these programs are \$5,928,400. 5 TR 1791; Exhibit A-106 (HWM-2), page 2, line 12.

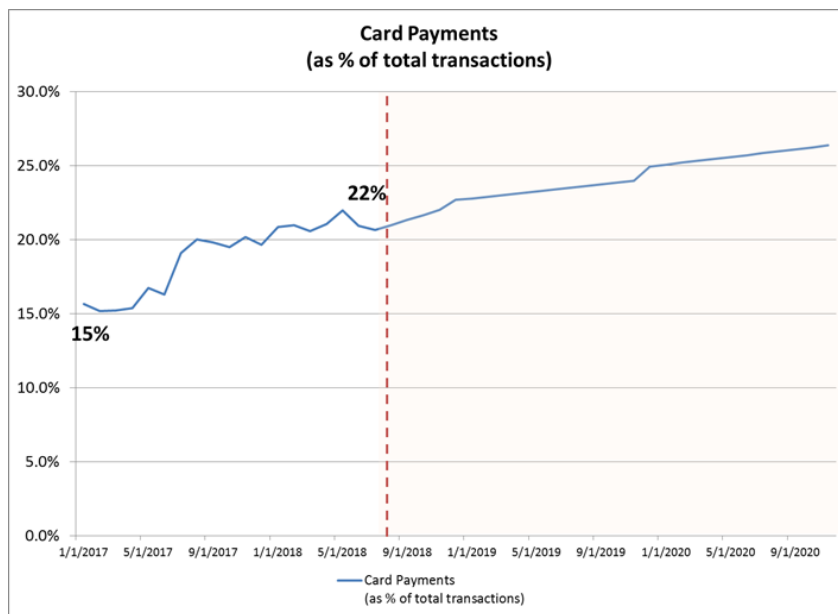
Mr. Miller testified that the Company's intent is to make payments as easy as possible with streamlined processes, friendly business rules, and no-fee payments. As such, in 2018 it removed the last remaining payment fee of \$1.75 for payments made at authorized third-party centers. There were 597,308 payments of this nature made in 2017 totaling over \$1,000,000 for all customers. In 2019, the Company projects this amount to be \$785,000 for electric and natural gas customers. The electric portion is estimated to be 51% of the \$785,000 which equates to \$400,000. 5 TR 1792; Exhibit A-106 (HWM-2), page 2, line 12.

b. Response To Staff

Staff witness Fromm proposed decreasing the test year O&M expenses associated with the Company's Customer Payment Program by \$768,400. 6 TR 2424; Exhibit S-9.2, line 4. Ms. Fromm cited Mr. Miller's testimony regarding the increase in O&M expense due to the phase-out of the \$1.75 fee the Company currently charges customers who pay their bill at a third-party payment location. She cited Mr. Miller's testimony that in 2017 there were 597,308 payments made at authorized third-party payment locations, totaling over \$1,000,000, and the Company's projected 2019 amount of \$785,000, of which 51% is attributed to the electric business, and that the Company expects to see an increase of \$400,000. By contrast, Exhibit A-106 (HWM-2), page 2, line 12 shows an increase from 2017 to 2019 of \$1,168,400. Ms. Fromm opined that this is contradictory to Mr. Miller's direct testimony, which only supports an increase of \$400,000 from 2017 to 2019. She therefore recommended the increase in excess of \$400,000 (\$768,400) be disallowed from the Company's O&M expense.

The Commission should not adopt Ms. Fromm's proposed disallowance, as it does not account for all relevant factors. Mr. Miller explained that the projected increase of \$400,000 in O&M expenses for eliminating convenience fees is a component of the overall increase in expenses, specifically the cost of removing fees associated with paying at third-party locations.

5 TR 1822. The remaining increase in O&M expense comprises fees associated with projected growth of credit card transactions as this continues to represent an increasingly common payment method for customers. Mr. Miller testified that the percentage of customers using credit cards to pay their electric bill has increased from approximately 15% in 2017 to over 20% in 2018, and over the next two years the Company projects the use of credit cards to increase to over 25%, as illustrated in the following chart (5 TR 1822) provided by Mr. Miller.



Thus, Ms. Fromm’s testimony did not account for the fact that customer payment program increases were based on these increases. Mr. Miller’s testimony that the expenses for eliminating convenience fees is a component of the overall increase in expenses, and that the remaining increase in O&M expense comprises fees associated with projected growth of credit card transactions, was unimpeached. The Commission, therefore, should not adopt Ms. Fromm’s position on this issue. The Commission should approve all of the Company’s Customer Payment Program O&M.

7. Corporate Services O&M Expense

Company witness Daniel L. Harry, Director of General Accounting, testified concerning the Corporate Services O&M projections. The Corporate Services O&M expense includes expenses for: (i) Human Resources and Administrative Services; (ii) Internal Control and Compliance; (iii) Legal; (iv) Corporate Risk Management; (v) Corporate Secretary and Corporate Compliance; (vi) Governmental/Public Affairs; (vii) Controller's Area; (viii) Rates and Regulatory Affairs; (ix) Strategy; (x) Corporate Tax; (xx) Financial Planning and Treasury; (xxx) General Activities costs; and (xl) Administrative and Other costs. 5 TR 2111-2112.

Mr. Harry calculated the projected test year Total Adjusted Corporate Services O&M expense to be \$52,562,000. Exhibit A-87 (DLH-1). This amount was calculated from the 2017 actuals, and projected amounts for 2018 and the 12 months ending December 31, 2019. 5 TR 2115; Exhibit A-88 (DLH-2). The test year O&M expenses were developed using the 2017 actual O&M expenses, which were taken from the Company's records, and then inflation factors for labor and non-labor were applied while seeking to limit the overall Corporate Services O&M expense increase to not more than the rate of inflation. 5 TR 2114-2115. Additionally, total Corporate Services expenses are normalized for significant increases or decreases related to unusual and/or one-time costs. 5 TR 2114. Disallowances were incorporated to account for various items that have been previously disallowed by the Commission. 5 TR 2114.

Consumers Energy's Corporate Services O&M expenses are reasonable and prudent. SNL Datasource ranked the electric side of Consumers Energy's 2016 administrative and general costs (excluding Pension and Benefits) the third lowest out of 63 companies on a cost-per-customer basis for electric companies with over 500,000 customers. 5 TR 2116; Exhibit A-89 (DLH-3). No party contested the Company's Corporate Services O&M expense.

8. IT O&M Expense

a. Company's Position

Company witness Hall's testimony concerning the Company's O&M projections for the IT Department (2 TR 253-255; Exhibit A-83 (JRH-1)) summarizes the Electric allocation of actual and projected IT Department O&M expense by cost category. Mr. Hall identified actual O&M expense in 2017 to be \$52,410,000, projected O&M expense in 2018 to be \$55,420,000, and projected O&M expenses in the 2019 projected test year to be \$53,875,000. The categories of IT O&M expense are: (i) Operations; (ii) Origination, and (iii) O&M Investments.¹⁷ With respect to the Operations category, Mr. Hall explained that:

“Operations expenses include the ongoing costs for the IT Department to support the various applications and infrastructure implemented through IT projects and enhancements. Critical incidents and system defect resolution is also included in this category. As the Company relies heavily on vendor support of critical applications and infrastructure including SAP, the contact center technologies, and digital customer products and services, contracts are the largest line item in the Operations O&M expense category. Stable and high-performing applications are critical in support of the Company's field operations and customers.” 2 TR 253.

Mr. Hall also detailed the Origination expense category as follows:

“Origination expenses are utilized during the concept phase of proposed IT projects. IT employees and contractors use this time to determine expected business objectives and outcomes, explore alternatives, perform a proof of concept, identify performance requirements, and to investigate the effectiveness of vendor products. The outcome of this work constitutes a rough order of magnitude for project costs weighed against the expected benefits to determine whether a proposed project should be approved for development and implementation.” 2 TR 253-254.

¹⁷ The O&M Investments cost category includes the O&M portion of capital projects, and according to FASB Subtopic 350-40 these project costs must be expensed.

Finally, Mr. Hall explained that IT O&M Investments include: “the one-time project related O&M expenses, as well as expenses for O&M only projects and enhancements.” 2 TR 254.

Mr. Hall explained that the Company’s 2017 IT Department O&M expenses were taken from the Company’s accounting records for the period January through December 2017. 2 TR 254. Included in these expenses are the internal and external labor costs associated with O&M the Company’s business software systems and computing, licensing of software systems, and maintenance contracts for computing infrastructure and communications networks. 2 TR 254. In projecting the 2018 and 2019 amounts included in Exhibit A- Exhibit A-83 (JRH-1), the Company considered the impact of numerous cost drivers.

An increase in O&M expenses is expected between 2017 and 2018 due to: (i) a one-time \$1.4 million credit from the Company’s support vendor in 2017 that does not extend into 2018; (ii) a \$420,000 increase in contractual third-party support costs, and (iii) a \$740,000 increase in circuit costs supporting the Company’s radio towers and dark fiber communication technologies. Mr. Hall further explained that: “[i]ncreased O&M expenses are a result of the continued investment in programs that both sustain and improve customer experience and customer interaction with the Company.” 2 TR 254-255. The Company’s IT Department is striving to maintain these critical enterprise systems to prevent risks to customer service and business operations, which could occur through system obsolescence. 2 TR 255.

Between 2018 and 2019, the Company projects a cost decrease of IT Department O&M expense. This is due to Company-wide efforts to decrease O&M through lean operations principles. 2 TR 255. Mr. Hall explained that the IT Department is projecting 3% to 4% O&M expense reductions from 2018 to 2019 which will mainly occur through efficiencies gained during contract negotiations and software licensing. 2 TR 255.

b. Response To Staff

Staff witness Theresa L. McMillan-Sepkoski recommended reducing IT Department O&M expenses by \$8,282,000 during the projected test year. 6 TR 2484. Ms. McMillan-Sepkoski believes that such an adjustment is necessary because she is of the opinion that a five-year historical average is a more reasonable approach to projecting IT O&M expense, and because she believes that the Company did not provide sufficient detail on Origination expenses. Ms. McMillan-Sepkoski's recommendation should be rejected because it fails to appropriately and reasonably project IT Department O&M expense for the projected test year.

In an effort to support her proposed use of a historical average to project future expense, Ms. McMillan-Sepkoski incorrectly concludes that the Company's IT Department O&M expenses have been "historically been volatile and/or sporadic." 6 TR 2486. Mr. Hall explained that the Company's IT Department's O&M expense is neither volatile nor sporadic. To demonstrate this point, Mr. Hall explained that the change in the Operations category of IT Department O&M expense is relative to the cumulative increase in IT investment growth year over year. 2 TR 285. This is significant because, historically the Operations cost category accounts for, on average, 75% of the electric IT O&M expense. 2 TR 286. The charts provided on 2 TR 285-286 of Mr. Hall's testimony has gradually increased over time as the Company's IT project investment increases.

Mr. Hall further explained that the O&M Investments cost category of IT Department O&M expense occurs every year, at varying levels, depending on the nature of the IT projects that are underway to meet the operational needs of the Company. 2 TR 286. These costs include all expenses that are incurred during the different stages of an IT project, such as the Preliminary Project Stage, Application Development Stage, and Post-implementation/Operation Stage. 2 TR

286. During these project stages, the Company determines performance requirements for a project, exploring alternatives, determines the technology needed, selects vendors and consultants, and incurs data conversion and training costs. 2 TR 286. The magnitude of these costs can vary from project to project based on each project's requirements, and is the primary reason for the increase in IT O&M expense from 2013 through 2017. 2 TR 286. Since the Company's IT Department O&M expenses are gradually increasing as the pace of IT investments increase, the use of a five-year average, as proposed by Ms. McMillan-Sepkoski, results in an unreasonably low O&M expense amount which fails to address customer and Company needs.

Ms. McMillan-Sepkoski is also incorrect in her assertion that the Company did not provide sufficient detail on the Origination cost category of IT Department O&M expense. The purpose of Origination expense is to document the justification for undertaking an idea before spending significant time and money. 2 TR 287. Mr. Hall explained that Origination expense is a subset of IT O&M expense added in 2014 to capture project initiation costs in a designated category. 2 TR 287. Giving the Origination category a specific designation provides the Company with a way to track the amount of spending on activities that are incurred as a result of due diligence. Mr. Hall further explained that not performing this due diligence would be irresponsible and likely more costly for the Company's customers as size, cost, complexity, and duration are all validated during the origination phase of the project. 2 TR 287.

It should further be noted that the Origination process is needed to support Staff witness Fromm's recommendation to provide an approval document for each project after the preliminary analysis phase. 2 TR 287. This includes an evaluation of alternatives, such as the consideration of cloud computing for project requests over \$100,000 excluding cyber security or

transmission control IT projects. 2 TR 287. If the Origination process is not sufficiently funded, it would inhibit, or potentially preclude, the Company's ability to appropriately consider project alternatives.

Ms. McMillan-Sepkoski's suggestion that Origination expense is "erratic and speculative" should also be rejected. 6 TR 2486-2487. Mr. Hall explained that Origination expense is not erratic, but relative to the number of projects that need to be evaluated in a given year. 2 TR 287. Origination expense is also not speculative because it is a part of standard project management practices. 2 TR 287. Completing a project initiation phase defines the project at a high level and researches whether the project is technically or financially feasible, and if it should be launched. Expensing these costs, as proposed by the Company, is also consistent with the accounting standards provided in Financial Accounting Standards Board ("FASB") 350-40.

Therefore, for the reasons explained above, Ms. McMillan-Sepkoski's proposal to use a five-year average to project IT O&M expense should be rejected. The Company's projection of IT Department O&M expense is based on existing costs and plans and appropriately addresses the Company's increased investment in IT projects.

9. Pension And Benefit O&M Expense

Consumers Energy projects a test year total electric O&M expense level for employee benefits of \$11,931,000. Exhibit A-65 (LBC-1), line 6, column (d). This test year employee benefit O&M expense amount was comprised of the following expenses: (i) Pension Plans; (ii) the Defined Company Contribution Plan ("DCCP"); (iii) 401(k) Employees Savings Plan; (iv) active employee health care, life insurance, and long-term disability ("LTD") insurance; and (v) retiree health care and life insurance. Exhibit A-65 (LBC-1).

Company witness Christopher, Manager of Health Care and Retirement, supported the total electric expense level for employee benefits. 5 TR 2026. She explained that Pension Plan expense is determined based on actuarially reviewed employee census data, plan provisions, plan assets, and certain other actuarial assumptions. 5 TR 2028-2029. The electric utility's projected pension expense was \$26,573,000 for the projected test year. 5 TR 2032; Exhibit A-65 (LBC-1), line 1, column (d). This expense amount was calculated using actuarial analysis performed by the Company's actuary, Aon Hewitt, in accordance with Accounting Standards Codification 715, using information specific to the Company's Pension Plan. 5 TR 2028-2032. The Company's auditors review the actuarial assumptions to ensure consistency with Generally Accepted Accounting Principles. 5 TR 2029.

In September 2005, the Company closed its Pension Plan for new hires and replaced it with the DCCP. 5 TR 2033. Under the DCCP, the Company makes a cash contribution of 5% to 7% of the employee's base wage into their 401(k) Employee Savings Plan. 5 TR 2035. Effective January 1, 2016, new hires received a 5% contribution, which will increase to 6% when they have six years of service, and then increase to 7% at 12 years of service. *Id.* This contribution occurs regardless of whether an employee contributes to the 401(k) Employee Savings Plan. *Id.* The Company projects a test year electric DCCP expense of \$9,025,000. 5 TR 2036; Exhibit A-65 (LBC-1), line 2, column (d).

The 401(k) Employee Savings Plan is funded by employee and employer contributions. 5 TR 2036. The Company matches 100% of the employee's first 3% in contributions and 50% of the employee's next 2% in contributions. For the test year, the projected electric 401(k) Employee Savings Plan expense is \$8,317,000. 5 TR 2037; Exhibit A-65 (LBC-1), line 3, column (d).

The Company's projected test year electric expense for active employee health care, life insurance, and LTD insurance, is \$25,145,000. 5 TR 2040; Exhibit A-65 (LBC-1), line 4, column (d). The primary component of this expense is health care. 5 TR 2039. Based on all of the data examined, the Company believes it can hold its annual health care cost increase to 3.5% in 2018 and 3.5% for the 12 months ending December 31, 2019. 5 TR 2043. For life insurance and LTD insurance for 2018 and the 12 months ending December 31, 2019, the Company reasonably projected a 3.5% annual increase based on wage and salary levels, and changes to this coverage throughout each year. 5 TR 2045-2046. The projected retiree health care and life insurance expense (or OPEB expense) for the test year is (\$57,129,000). 5 TR 2055; Exhibit A-65 (LBC-1), line 5, column (d).

All of Consumers Energy's above-discussed test year total electric O&M expense level for employee benefits was fully supported by Ms. Christopher's testimony and exhibits. No parties witness challenged the Company's request to recover \$11,931,000 for its employee benefits projected test year amount, and Ms. Christopher's testimony was un rebutted and unimpeached. Consumers Energy, therefore, submits that the Commission should approve the full amount for recovery in rates.

10. EICP Expense

In Case No. U-18124, in its July 31, 2017 Order in Consumers Energy's gas rate case, the Commission authorized the Company to recover, in rates, the portion of Consumers Energy's EICP costs linked to operating performance metrics. See MPSC Case No. U-18124, July 31, 2017 Order, page 87. The Commission again permitted recovery of the Company's EICP operating performance metrics in Consumers Energy's most recent electric case. MPSC Case No. U-18322, March 29, 2018 Order, page 67. In this current case, Consumers Energy requests the Commission to authorize recovery in rates of the entirety of its EICP costs in the amount of

\$5.03 million for the projected test year, as shown on Exhibit A-72 (AMC-3). This expense level consists of the EICP linked to operating performance metrics, totaling \$1.740 million, and the portion of the EICP linked to financial performance metrics, totaling \$3.289 million.¹⁸ As explained below, these elements of the Company's overall employee compensation package constitute reasonable components of the Company's market-based overall employee pay and create beneficial incentives for employees to improve performance and achieve targeted performance goals which benefit customers.

a. Consumers Energy's Overall Compensation Philosophy And Structure Is Reasonable

Consumers Energy witness Amy M. Conrad, Director of Executive and Incentive Compensation, testified regarding the Company's overall employee compensation philosophy and structure. Ms. Conrad's testimony and exhibits support recovery of the incentive portion of the package of compensation provided to non-union Company employees.¹⁹ See, generally, 5 TR 2060 *et seq.*

Consumers Energy's management believes that 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 supports the highest level of customer service at a reasonable cost. 5 TR 2066. In setting a reasonable level of compensation, Company witness Conrad testified that Consumers Energy's management actively reviews compensation levels so that employees are neither overpaid or underpaid relative to the market, and uses a rigorous

¹⁸ While believing it to be a reasonable and prudent expense amount, Consumers Energy is not requesting recovery in rates of the long-term incentive costs in this proceeding. In addition, Consumers Energy is allocating to shareholders 100% of the costs of incentive compensation for the proxy officers, as identified by the SEC proxy rules. 5 TR 2063.

¹⁹ Employees who are rated as "under-contributing" on their annual performance appraisal are not eligible for incentive compensation. 5 TR 2065.

survey process which uses valid and reliable data from multiple sources to determine median levels of compensation. 5 TR 2068. Compensation levels are actively monitored, and the Company engages in a rigorous benchmarking analysis of comparable jobs and rates of pay. 5 TR 2069-2073. The Company's process of researching market pay data ensures that the Company's compensation levels match the relevant market, and are not inflated over prevailing market levels. 5 TR 2071; see Exhibit A-71 (AMC-2). This total overall market-based, competitive level of pay is then allocated into components of: (i) base salary, and (ii) incentive compensation. 5 TR 2066. The incentive compensation is one component of the overall market-based competitive compensation; it is not an addition to the total overall market-based pay. 5 TR 2086. The total compensation (base pay plus incentive compensation) is targeted at approximately the market median (50th percentile). 5 TR 2063.

The Company's officer compensation levels are determined by the Compensation Committees of the Boards of Directors of Consumers Energy and CMS Energy. In determining individual officer compensation levels, the Compensation Committees are advised by an independent third-party consultant and consider market research, experience levels, and individual contributions. 5 TR 2063 *et seq.* Ms. Conrad explained that the compensation package for officers includes: (i) base salary; (ii) short-term (annual) incentive compensation; and (iii) long-term incentive compensation. These three components in total are targeted at the median (50th percentile) of the competitive market based pay. 5 TR 2066. If any of these components were reduced or eliminated, one or both of the other components would need to be correspondingly increased to remain competitive. *Id.*

The Company's overall compensation levels, including the officer and non-officer incentive compensation, are reasonable compared to the market, and that compensation without

the incentive compensation would constitute below market pay. 5 TR 2063-2065. If the Company were to compensate employees at uncompetitive levels of pay, the result would be a lower qualified workforce. 5 TR 2064. Consumers Energy has a responsibility to customers to employ a competent workforce that is ready, willing, and able to provide service for our customers. Paying competitive wages and salaries is necessary in order to fulfill that commitment. 5 TR 2068.

b. The Structure And Benefits Of Consumers Energy's Incentive Compensation Plan

Consumers Energy's employee compensation is thoughtfully determined to ensure that it is reasonable and commensurate with comparable market-based salaries for similar positions. Ms. Conrad explained that the Company's incentive compensation plan structure is supported by substantial and significant research, testifying as follows:

“A wide body of research supports the view that variable pay 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’ – World-at-Work Press, 2007). I agree with this assessment. 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. 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 percent. (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).” 5 TR 2066-2067.

Consumers Energy's practice of making a portion of overall employee compensation subject to incentives is consistent with best industry practices for compensation. 5 TR 2072.

The Company's incentive compensation plans are designed to emphasize and promote operational and performance objectives in areas that are critical to the Company's utility service. 5 TR 2079. Focusing employees on those goals provides qualitative and quantitative benefits for the Company's customers. With incentive compensation, the employees and the Company as a whole must re-earn the at-risk incentive compensation each year. If the targeted high levels of performance are not achieved, employees' incentive pay is reduced or eliminated. 5 TR 2081. Customers benefit from incentive pay because the elimination of the variable at-risk incentive pay would mean that all compensation would be guaranteed and an important incentive to improve service would be eliminated. This result would be harmful to customers.

Consumers Energy's incentive pay structure includes a short-term incentive plan, called the EICP, which is designed to focus and reward achievement of performance goals over periods of approximately one year or less. The EICP goals are structured to encourage employees to provide reliable energy, customer value, and responsive service to our customers, and to do so safely. The 2018 EICP Performance Measures are summarized on Exhibit A-70 (AMC-1), which identifies the operational performance and financial performance areas of the EICP and the specific measure adopted for each area. The non-officer EICP equally weighs the operational and performance measures of safety, reliability, and customer value with the financial measures:

- “• Half (50%) of employees’ incentive will be based on achievement of operational performance measures. (For 2018, there are nine operational measures.); and
- “• Half (50%) 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.” 5 TR 2065.

The officer EICP has the same goals, but the weightings are different. The operational goals are a plus or minus modifier to the financial goals. 5 TR 2065.

Consumers Energy is seeking recovery of EICP expenses at the 100% payout level. 5 TR 2085. 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. 5 TR 2091. The EICP payout levels (shown on Exhibit A-70 (AMC-1)) are established so that the threshold is at a level of achievement that can typically be met 8 or 9 times out of every 10 years. 5 TR 2081. Maximum payout is for exceptional performance and is expected to be achieved 1 or 2 times every 10 years. *Id.*

Ms. Conrad further explained:

“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 less 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.” 5 TR 2081.

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 less customer benefits. 5 TR 2081.

(i.) **The Achievement Of Company-Established Operational Metrics Provides Benefits To Customers**

The operational metrics included in the EICP provide benefits to customers, which significantly exceed the costs related to the incentive portion of compensation. For 2018, Consumers Energy established specific performance measures for non-officer employees, which encompass critical areas of the Company's operations. For example, Consumers Energy has a breakthrough goal related to safety of the public. Additionally, the Company has set a number of continuous improvement operational goals related to customer experience, employee safety, cyber security, customer on-time delivery, distribution reliability, generation customer value, and compression availability. Exhibit A-70 (AMC-1). Ultimately, the Company's operational performance measures focus on areas of employee safety, public safety, reliability, cost, delivery, and customer care. 5 TR 2080.

Although specific quantification of the costs and the benefits is not easy to perform for every metric included in the EICP calculation, the Company has evaluated the direct quantitative benefits of certain program metrics, and has assessed indirect and/or qualitative benefits associated with the other metrics. The annual benefit to electric customers achieved from the performance measures quantified is in excess of \$182.9 million. 5 TR 2173. This amount represents the operational benefits allocated to electric customers, which is based on the total number of electric employees as a percentage number of Consumers Energy employees. 5 TR 2172-2173. The benefits of the EICP Program far exceed the EICP costs allocated to electric customers. Moreover, as Company witness Daniel G. Shirkey testified:

“...the design of the incentive plan 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.” 5 TR 2174.

If quantifiable customer benefits are used as a criterion for recovery, the Company has met this threshold requirement, and the evidence shows that the operational measures provide appreciable benefits to customers and that the benefits to customers from the annual incentive compensation exceed the costs to customers of the EICP Program.

MEC/NRDC/SC/EC/MEIBC witness Jester contends that the Commission should consider the availability of specific performance incentives when applying broad performance criteria to the Company’s executive compensation or EICP. 6 TR 2593. Specifically, Mr. Jester contends that the Company should be directed to make a different proposal related to its employee compensation and tie any incentive compensation to affordability, reliability, pollutant emissions, and other criteria directly measuring the Company’s performance for its customers and society. 6 TR 2598. However, this proposal dismisses the fact that the Company already designs the portion of its pay related to incentive compensation on metrics that provide benefits to customers. As currently structured, the EICP is designed to lower costs and improve service to customers. On an annual basis, the Company designs its EICP goals. Each year, the Company identifies key operational and financial metrics to focus on for the next year. The operational metrics have been developed under two general categories: (i) continuous improvement and (ii) breakthrough. Continuous improvement metrics are key operational goals that focus on continuously evaluating work and delivery processes for opportunities for improvement (e.g., waste elimination, first time quality, etc.) to enhance productivity and customer value. Breakthrough metrics are aggressive, strategic goals that will position the

Company to continue to be competitive in the future. 5 TR 2168. This allows the Company to tailor a portion of its compensation to specific goals of the Company that will also provide customer benefits. Company witness Shirkey testified that: “[t]here 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.” 5 TR 2168.

Mr. Jester’s proposal also ignores the fact that the Company’s operational performance measures focus on areas of employee safety, public safety, reliability, cost, delivery, and customer care (5 TR 2080), which are many of the criteria cited by Mr. Jester. While Mr. Jester advocates for a number of considerations in his testimony including performance-based ratemaking, he does not make any clear or firm recommendations on which the Commission could act. Requesting that the Company make broad changes to its compensation methodology in the Company’s next general rate case is not appropriate. The Commission regulates a number of regulated utilities, not just Consumers Energy, and any potential changes to compensation as it relates to performance-based ratemaking should include all utility stakeholders. A single utility’s general rate case is not the appropriate venue for such a discussion. 3 TR 561.

(ii.) **The Achievement Of Company-Established Financial Metrics Provides Benefits To Customers**

The financial metrics included in the EICP also provide benefits to customers. Consistent financial performance is the result of total company performance including achieving operational success. Thus, it is of critical importance that Consumers Energy remains financially strong so that it can provide the utility service that customers expect and deserve. 5 TR 2102. Including financial goals as part of the EICP performance metrics helps to focus employees on achieving superior results in a cost-effective manner. 5 TR 2102-2103. In

addition, if the Company is financially healthy, it will be easier to raise funds needed for capital investments on reasonable terms and conditions, and maintain an attractive cost of capital. 5 TR 2103; 3 TR 470-472. As shown on Exhibit A-14 (SM-1), Schedule D-5, page 8, the Company has saved ratepayers \$47 million as a result of improved credit ratings and lowered interest costs; thus, illustrating the importance of including financial metrics as part of the EICP.

Staff witness Harris disagreed with the inclusion of EICP expenses related to financial based performance metrics, and suggested that the EICP financial metrics mostly benefit investors and not customers. 6 TR 2464. Similarly, MEC/NRDC/SC/EC/MEIBC witness Jester argued that in future cases the Commission should exclude incentive compensation based on financial performance. 6 TR 2584. The evidence presented by Consumers Energy in this case disputes these assertions. While financial incentives may provide benefits to shareholders, this does not mean that they also do not provide meaningful benefits to customers. 5 TR 2102. Moreover, under the Company's proposal, shareholders bear a portion of the EICP costs. Ms. Conrad explained that the Company is including incentive compensation costs at target levels, which will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target levels. This results in shareholders absorbing any resulting increases in costs arising from above targeted performance. 5 TR 2085.

Consumers Energy has also presented evidence in this case that having a financially healthy utility provides appreciable benefits to customers. Ms. Conrad stated:

“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 other operational and 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." 5 TR 2082.

Moreover, the two financial measures used to determine EICP, Earnings and Operating Cash Flow ("OCF"), are critical to attracting capital and maintaining credit, both of which benefit customers by enabling necessary investments and lowering interest costs. 3 TR 555.

Company witness Maddipati testified:

"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." 3 TR 471.

Incentivizing employees to achieve Earnings and OCF targets is critical to maintain ratings and provides tangible benefits to customers.

c. Conclusion

Customers receive quantitative and qualitative benefits by having a portion of compensation attributable to the EICP Program since the goals of the EICP Program are in the interests of customers. Customer benefits are achieved without any additional cost above market to customers since this program has been structured as a "carve out" of the employee's base salary. 5 TR 2092. Research shows that incentive compensation plans, like Consumers Energy's EICP, motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. 5 TR 2093. Consumers Energy's overall compensation levels are reasonable, and incentive compensation is a component of the overall

reasonable compensation level. Therefore, for the reasons set forth above, and in the record evidence presented by the Company, Consumers Energy requests that the Commission approve recovery of the entire EICP expense in rates.

11. DR Expense

The Company's test year O&M costs for its residential and business DR programs are \$12,475,000. 5 TR 1798; Exhibit A-106 (HWM-2), page 1, lines 14 and 19. The test year O&M for the business DR Program is \$5,755,000 (5 TR 1799; Exhibit A-106 (HWM-2), page 1, line 14); and the test year O&M for the residential DR Program is \$6,720,000 (5 TR 1802; Exhibit A-106 (HWM-2), page 1, line 19). These DR programs were discussed above in Section III.A.6.a., and were fully supported by the testimony and exhibits of Mr. Miller. As also discussed in Section III.A.6.a.(ii), Staff favored its own CPP DR provision to the Company's UPR, but Staff did not propose any disallowances to DR expense, nor did any other parties' witness. Thus, the Commission should approve the test year O&M expenditures in their entirety.

12. Uncollectible Expense

The Company projected the uncollectible accounts expense for the test year to be \$18.6 million. 5 TR 2117; Exhibit A-90 (DLH-4). To calculate the uncollectible expense, the Company used a three-year average Bad Debt Loss Ratio of cash basis uncollectible accounts expense to electric service revenue for the years 2015 through 2017. 5 TR 2117; Exhibit A-90 (DLH-4). This ratio was applied to the test year electric service revenue plus surcharge revenue to arrive at the sub-total of test year uncollectible accounts expense. 5 TR 2117. The estimated impact of the Smart Grid/Advanced Metering Infrastructure ("AMI") Program benefits on uncollectible accounts expense was then incorporated to arrive at the total uncollectible accounts expense. 5 TR 2118. This methodology allows for the calculation of a reasonable estimate of the Company's uncollectible expense, which is impacted by factors that tend to fluctuate over

time, such as the economy and fuel and purchased power cost prices. 5 TR 2119. No party challenged the Company's calculation of its forecasted uncollectible expense amount in this case.

13. Electric Injuries And Damages Expense

a. Company's Position

The Company's Electric Injuries and Damages expense includes 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; accidents and lawsuits (up to a \$500,000 insurance deductible per occurrence); and workers' compensation costs. 5 TR 2120. For the test year, the Company projected an expense level of \$4.7 million for its Electric Injuries and Damages expense. 5 TR 2120; Exhibit A-91 (DLH-5). Company witness Harry explained that the Company's projection is comprised of three components: (i) electric injuries and damages; (ii) internal legal costs; and (iii) workers' compensation costs. 5 TR 2120. The test year amounts of these three components are based on a five-year average of actual expense for the years 2013 through 2017. 5 TR 2120.

b. Response To RCG

RCG witness Peloquin takes issue with the Company's proposed Injuries and Damages expense amount, except for the workers' compensation claim portion, claiming that many of these expenses are the result of Consumers Energy's own negligence. 7 TR 3178. Mr. Peloquin provides no exhibits or citation to any other support for his speculation that any part of these expenses are due to negligence on the part of Consumers Energy.

As noted above, these expenses typically include compensation for damaged trees, crops, driveways, lawns, and fences. 5 TR 2129-2130. These are the types of property that are frequently damaged simply as a result of the nature of the Company's work, not as a result of

negligence. For example, it may be necessary to damage crops in order to access land where the Company needs to repair damaged electric distribution infrastructure. Company witness Harry reiterate in his rebuttal testimony that Injuries and Damages expenses arise out of the normal course of providing electric utility service to customers. 5 TR 2129. The Commission has consistently used a five-year historical average of actual expenses to project these expenses in all of the Company's recent electric and natural gas rate cases. 5 TR 2130. RCG simply provides no factual basis to support removing recovery of these legitimate costs from rates.

D. Depreciation And Amortization Expense

The Company used the Commission-approved depreciation rates, along with the projected capital expenditures and assumed plant retirements, in the determination of the depreciation expense adjustment necessary to arrive at an appropriate level of book depreciation expense. 2 TR 338. Book depreciation expense was developed by applying the functional composite book depreciation rates to the average projected test year depreciable plant balances. 2 TR 338. The adjustment on Exhibit A-13 (HJM-62), Schedule C-14, line 21, increases depreciation expense from the historical period due to significant new investment. 2 TR 332. The Company revised its originally-filed depreciation expense based on certain adjustments to the Company's originally-filed revenue deficiency. See Exhibit A-166 (HJM-69).

The Commission should reject Staff's proposed depreciation expense. Staff's proposed depreciation expense is based, in part, on Staff's proposed adjustments to the Company's projected plant-in-service. 6 TR 2462. The Company's disagreement with certain of these proposed adjustments, is discussed elsewhere in this Initial Brief.

E. Taxes

1. Property Tax

Company witness Brian J. VanBlarcum, Property Tax Manager in the Company's Corporate Tax Department, testified on behalf of the Company concerning property tax. Mr. VanBlarcum testified that the test period property tax expense is projected to be \$174.5 million. 5 TR 2180. Mr. VanBlarcum set forth the methodology he used to reach that projection in his testimony. See 5 TR 2179-2181; Exhibit A-114 (BJV-1). No party contested Mr. VanBlarcum's calculation of the Company's property tax expense.

2. Federal, Michigan, And Local Income Taxes

Company witness Myers presented the Company's projected General Taxes, projected Federal Income Taxes, projected State Income Taxes, and projected Other (or Local) Taxes. 2 TR 334. The Company projects Real and Personal Property Tax expense in the jurisdictional amount of \$168,379,000; General Tax expense in the jurisdictional amount of \$30,589,000; Local Income Tax expense in the jurisdictional amount of \$1,324,000; Michigan Corporate Income Tax expense in the jurisdictional amount of \$39,685,000; and Federal Income Tax expense in the jurisdictional amount of \$113,867,000. Appendix C, page 1, lines 8 through 12, column (e); Exhibit A-166 (HJM-69).

Staff witness Robert F. Nichols II's projected Federal, Michigan, and Local Income Tax amounts should be rejected. See Exhibit S-3, Schedule C-1. These amounts rely on incorrect adjustments to projected revenue, Other O&M expense, and depreciation expense which have been addressed by the Company throughout this Initial Brief.

F. Allowance For Funds Used During Construction

The criteria for applying Allowance for Funds Used During Construction ("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. 2 TR 339. Consumers Energy has calculated a test year jurisdictional AFUDC level of \$8,784,000. Appendix C, page 1, line 15, column (e); Exhibit A-166 (HJM-69). Staff did not recommend any adjustments to the Company's proposed AFUDC amount. See Exhibit S-3, Schedule C-1, line 15.

G. Calculation Of Adjusted Net Operating Income

Total jurisdictional revenues of the Company are \$4,325,620,000, as shown in Appendix C, page 1, line 4, column (e), Exhibit A-166 (HJM-69). After expenses, Net Operating Income ("NOI") is \$626,703,000. Appendix C, page 1, line 14, column (e); Exhibit A-166 (HJM-69). Adjusting for AFUDC leaves an adjusted NOI of \$635,487,000. Appendix C, page 1, line 19, column (e); Exhibit A-166 (HJM-69). Staff's proposed adjusted NOI is \$647,193,000. Exhibit S-3, Schedule C-1, line 16.

VI. OTHER REVENUE, ACCOUNTING, AND PERFORMANCE ISSUES

A. IRM

1. Company's Position

Consumers Energy is requesting the Commission authorize an IRM for its electric business. 2 TR 82-86, 340-345. The IRM proposed by the Company includes six programs, covering all of the Company's capital spending for its distribution part of the business. 2 TR 83. The six distribution capital programs are: (i) New Business; (ii) Demand Failures; (iii) Asset Relocation; (iv) Reliability; (v) Capacity; and (vi) Tools and Technology. 2 TR 83. This proposed capital spending is supported in detail by the Company's EDIIP report filed with the Commission on March 1, 2018, as discussed in the direct testimony of Company witness Sparks. 2 TR 160-167.

Company witness Myers explained that the IRM provides for recovery of the 2020 and 2021 average incremental electric distribution rate base, and the associated direct expenses

beyond the level ultimately approved in test year. 2 TR 340; Exhibit A-109 (HJM-65). The IRM calculates the incremental revenue requirement associated with recovery of these incremental investment amounts and will operate through a surcharge that is effective January 1, 2020 until rates are reset in a subsequent rate case. 2 TR 340. For 2020, the IRM proposed by the Company would recover \$49 million of incremental revenue requirements, and for 2021, it would recover \$48 million of incremental revenue requirements. 2 TR 343-344.

Following the end of 2020, the Company will file a contested reconciliation which updates the initial incremental revenue requirement calculation with actual balances and determines if the actual incremental capital spending is greater or less than projected amounts reflected in the surcharge rates. 2 TR 341. If actual capital spending for the 2020 period is less than the Commission-approved amounts, a credit will be established to return the difference in the incremental revenue requirement to customers. 2 TR 341. Similarly, the Company would file another contested reconciliation proceeding at the conclusion of the 2021 period. 2 TR 341. Again, if the 2021 reconciliation shows an incremental revenue requirement lower than that approved by the Commission, a credit will be calculated based on the difference. 2 TR 341. Thereafter, the IRM surcharge will be adjusted to reflect the level of incremental revenue requirement approved in the 2021 reconciliation, and the Company will annually submit a reconciliation filing to adjust the surcharge to reflect the increase in the depreciation reserve associated with the actual 2020 and 2021 electric distribution capital spending until rates are reset in a general rate case. 2 TR 341-342.

As proposed by the Company, the IRM would permit flexibility to shift actual capital spending dollars among the separate programs of electric distribution capital spending with the reconciliation applied to total approved IRM capital spending. 2 TR 342. The Company's

proposed IRM would also include an IRM Excess Return Sharing Mechanism applicable in the IRM years 2020, and beyond in order to provide assurance that the IRM would not result in excess earnings above the reasonable range proposed in this case. 3 TR 466. During the time the IRM is in effect, the IRM Excess Return Sharing Mechanism would permit the Company to keep all earnings up to top of the 11.00% ROE range supported in the testimony of Company witness Maddipati. 3 TR 466. Above that range, the Company would agree to refund 50% of the earnings that exceed 11.00% ROE up to 12% ROE and to refund 100% of the earnings that exceed 12% ROE during the time the IRM is in effect. 3 TR 466-467. The IRM Excess Return Sharing Mechanism would be a one-way mechanism, meaning that it would not operate to provide any additional revenue to Consumers Energy in the event that the earned ROE during the time the IRM is in effect, drops below the 10% bottom threshold of the ROE range supported by Mr. Maddipati in this case. 3 TR 466.

Furthermore, the Company has indicated that, under certain conditions, it would be willing to commit to staying out of a new electric rate case filing for a period of time if the IRM proposed by the Company is approved. Mr. Torrey testified:

“If its IRM proposal is approved, Consumers Energy believes it can defer the need for an electric base rate reset until January 2022. In other words, under the current 10-month statutory construct, Consumers Energy would not file another electric general rate case until late February 2021.

“In order to defer the filing of its next electric general rate case to late February 2021 the following has to occur: (i) acceptable and timely rate relief in this proceeding and (ii) approval of the IRM as proposed in this proceeding. Consumers Energy would need the ability to review the Commission’s order in this proceeding before committing to deferral of the next electric general rate case. Both the amount of rate relief granted for the 2019 test year and the terms and conditions of the IRM applicable to 2020 and 2021 must

be reviewed and determined to be acceptable in order to commit to defer the next electric general rate case.” 2 TR 84-85.

In order to provide the review opportunity discussed in Mr. Torrey’s testimony, the Company requests that the Commission provide a 14-day window following the order in this proceeding to accept the terms and conditions of the approved IRM. 2 TR 85. While Mr. Torrey also noted in his testimony that the Company would necessarily need to reserve the ultimate right to file a new rate case if some unforeseen event occurs, which might have a severe detrimental impact on the Company’s financial health (2 TR 86), he further explained that the Commission has the authority to approve deferred accounting relief as necessary to address issues such as catastrophic storms, changes in state or federal energy policy or tax law, the loss of a major customer, or other similar items that might otherwise activate that reservation of rights. 2 TR 102. Mr. Torrey committed that the Company would seek deferred accounting approval for such items before deciding to file its next electric general rate case prior to February 2021, if the conditions necessary to make the commitment to stay out of a rate case for some period have been met. 2 TR 102.

Company witness Myers presented testimony explaining the calculation of the IRM incremental revenue requirement. 2 TR 343-345. Exhibit A-109 (HJM-65) calculates the average incremental rate base and average depreciation reserve arising from the 2020 and 2021 projected capital expenditures. 2 TR 345. Revised Exhibit A-108 (HJM-64) calculates the incremental annual revenue requirement associated with the incremental rate base and depreciation reserve. 2 TR 344. The incremental revenue requirement from the 2020 and 2021 incremental rate base equals the sum of: (i) the incremental return on rate base; (ii) the incremental depreciation expense; (iii) the incremental property tax; and (iv) the incremental AFUDC offset amount. 2 TR 344. Exhibit A-68 (LMC-5) provides an illustrative calculation of

the proposed IRM surcharge. 5 TR 1575. The Company is proposing to collect the incremental revenue through demand and energy surcharges for each rate schedule. 5 TR 1575-1576. The revenue requirement for each class is based on the cost allocation of the revenue requirement as shown in Exhibit A-32 (JCA-5). 5 TR 1576. The surcharge is based on test year sale, and would apply to both Full Service and ROA customers. 5 TR 1576.

The Company's IRM in this case is reasonable and should be approved. It would benefit both customers, and the Company, by facilitating capital investments needed to improve distribution safety and reliability for customers through the end of 2021, while simultaneously providing timely and modest²⁰ cost recovery. Customers get price certainty and predictability over the next couple of years, and they get the protection of a reconciliation procedure that would ensure they pay for no more than they reasonably and prudently get, in terms of new distribution investments. 2 TR 99. The Commission should approve the Company's IRM as proposed.

2. Areas Of Dispute With Various Parties

Staff, the Attorney General, ABATE, The Kroger Co. ("Kroger"), MEC/NRDC/SC/EC/MEIBC, and RCG criticized the Company's IRM proposal. The five common criticisms repeated by more than one of these parties are: (i) that the IRM shifts risks to customers without a corresponding reduction in the Company's rate of return; (ii) that the EDIP is not adequate to serve as support for the spending proposals included in the IRM; (iii) that the IRM does not provide for an adequate prudence review; (iv) that the IRM is a single issue

²⁰ The average annual rate increase in Consumers Energy's last five rate cases has been \$104.6 million (\$118.5 million in Case No. U-16794; \$89 million in Case No. U-17087; \$130.1 million in Case No. U-17735; \$113.3 million in Case No. U-17990; and \$72.3 million in Case No. U-18322). Each of the annual increases requested as part of this IRM is less than half of the average annual increases associated with the Company's last five rate cases, and more than 30% lower than the lowest annual rate increase awarded over that time.

ratemaking adjustment which is not sound regulatory practice; and (v) that the timing is not right to delay rate case filings if an IRM is approved. 2 TR 96. In addition to these common criticisms, several parties include additional criticisms that are not shared by other parties. All of these criticisms are unfounded and should be rejected by the Commission. The Company addresses the first of these common criticisms in Section IV.C.1.e. of this Initial Brief (discussing the Company's proposed ROE in this case) above. The remaining criticisms are addressed in the following sections.

a. The EDIIP Provides Sufficient Detail To Support The Spending Proposed In The IRM

As discussed previously in Section III.A.1 of this Initial Brief, the Company's EDIIP presents a detailed, multi-year plan for investing in and maintaining the electric distribution system. This plan is optimized by customer-driven objectives for safety, reliability, cost, control, and sustainability. 2 TR 165. The EDIIP describes the projected scope of work, prioritization rationale, and customer benefits of the Company's investments. The Company utilized the Grid MD model as a tool to inform what reliability improvements would be made to the system in order to achieve 120 minutes SAIDI by year-end 2022.²¹ 5 TR 1982. Table 17 on Exhibit A-111 (TJS-1), page 86, provides a summary of the Company's electric distribution capital investment plan for the five-year period of 2018 through 2022, along with actual historical investments for years 2015 through 2017. Table 17 reflects the six programs that the Company has included in its IRM - New Business, Demand Failures, Asset Relocations, Reliability, Capacity, and Tools and Technology (labeled 1.0 through 6.0 in Table 17 of Exhibit A-111 (TJS-1)). 2 TR 165.

²¹ Staff raised some concerns regarding the Company's Grid MD model. 6 TR 2272-2274. The comments raised by Staff are conflicting and the conclusions drawn are unsupported. Company witness Anderson discusses Staff's criticism at 5 TR 1980-1982.

Staff witness Ryan Laruwe recommends that the Commission not approve the Company's proposed IRM claiming that the spending plans were vague and insufficient to perform an adequate prudency review. 6 TR 2271. MEC/NRDC/SC/EC/MEIBC witness Jester and Attorney General witness Coppola offer similar criticisms. 6 TR 2609, 2818. However, the reasonableness of these projected expenditures was supported by the Company's EDIIP, which is a comprehensive distribution plan that provides a detailed explanation of how the investments for each of the capital programs included in the IRM were developed. The Company's EDIIP includes nearly 300 pages of data and narrative detail presenting the Company's future vision for the electric distribution system, performance objectives and metrics, current state of the system, and investment and maintenance plans for 2018 through 2022. 2 TR 170. Nearly two-thirds of the report consists of detailed breakdowns of planned capital investments and scope for each program, sub-program, and investment category over that five-year period. Each program section of the report provides detailed explanations of the investment logic and prioritization process that the Company uses to make reasonable and prudent investments for the benefit of its customers. 2 TR 170.

Consumers Energy's EDIIP directly addresses the concerns of the Commission. In the October 11, 2017 Order, in Case No. U-17990, the Commission specified that the Company's EDIIP should focus primarily on near-term priorities of safety, aging infrastructure, and reliability and resiliency.²² The Company's EDIIP rightly focused on these items, which are the

²² Parties to this proceeding have indicated that the Company's distribution plan should take into greater consideration non-traditional alternatives such as non-wires alternatives, DER, etc... See, e.g., 6 TR 2271, 2608, 2674-2681. Consumers Energy agrees that these are important items to consider. However, foundational work to the distribution system needs to first be undertaken. Company witness Sparks testified, "[h]owever, when considering "non-traditional" investments, such as grid modernization solutions, battery storage, or other NWAs like DR, the Company first will need to maintain and upgrade its existing, aging infrastructure, but also increase investment in modernizing the grid (through a combination of telecommunications, grid devices, analytics, and

foundational items needed for continued investments in grid modernization. 2 TR 187. The Company's EDIIP provides the Company's reasoning for determining HVD and LVD capital spending and O&M needs, and provides the Commission with detailed information to help evaluate the Company's proposals. 2 TR 174. In approving the IRM, based on the EDIIP, the Commission is approving a multi-year plan to work toward laying the foundation for future nontraditional investments.

Moreover, the EDIIP is sufficient for the basis of the IRM. Staff has never previously made any assertion that the EDIIP did not meet the requirements set by the Commission. In fact, the opposite is true. On page 11 of Staff's Report on Michigan Distribution Planning Framework ("September 1, 2018 Report"), Staff reported that "each utility provided an excellent presentation of system data regarding asset age and the risk to system reliability and safety presented by this aging infrastructure, and the need for additional investment to mitigate the risk associated with these assets is undeniable." Staff continued indicating that "the transparency provided by these reports will undoubtedly aid in the review and improve the efficiency of rate case review of utility programs to address aging infrastructure investments in the near-term." September 1, 2018 Report, page 11. The September 1, 2018 Report further stated that "the submitted plans provide a great level of insight into existing risks on the distribution system as well as the utilities' preferred approach to addressing these risks. The clear and present risk to system safety and reliability due to aging infrastructure needs to be addressed in the near term." September 1, 2018 Report, page 11. For these very reasons, the EDIIP is sufficient to support the Company's requested IRM.

advanced applications). In other words, a core, interoperable platform must be established first, upon which the Company can begin to build scalable advanced grid applications and capabilities." 2 TR 174.

Additionally, use of the EDIIP to support the IRM is consistent with the Commission's past guidance. MPSC Case No. U-17990, October 11, 2017 Order, page 15, states that "[w]hile this planning process would not provide regulatory approvals for cost recovery purposes, the transparency around the need for, scope of, and expected outcomes resulting from specific investment strategies may facilitate ratemaking processes and the development of potential new approaches to provide greater regulatory certainty, such as performance-based ratemaking currently being studied pursuant to the 2016 energy laws." In other words, the Commission made it clear that the EDIIP could be used to facilitate new approaches to ratemaking, such as the Company's proposed IRM. The Company did so in this case.

b. MEC/NRDC/SC/EC/MEIBC's And The Attorney General's Claim That The IRM Does Not Offer Sufficient Prudency Review Is Based On A Misunderstanding Of The Company's Proposal

MEC/NRDC/SC/EC/MEIBC witness Jester and Attorney General witness Coppola each assert that the Company's proposed IRM does not provide a sufficient prudency review of the capital expenditures included in the IRM. 6 TR 2609, 2818-2820. However, these parties misunderstand the Company's proposal and the numerous opportunities for prudency review that it affords. The Company's proposed IRM includes the opportunity for more reviews and Staff audits, than capital expenditures that are approved through traditional ratemaking. 2 TR 98. Company witness Torrey explained that the capital expenditures included in the IRM are subjected to the same level of review in this case as all other proposed test year capital expenditures. 2 TR 97. Additionally, as comprehensively explained in the section above and in the Company's testimony and exhibits, the incremental capital expenditures included in the IRM are subject to a second review in the IRM reconciliation case that is not afforded to capital expenditures that are not subject to the IRM. 2 TR 97-98, 341-342.

Attorney General witness Coppola acknowledges that the opportunity for prudency review in the reconciliation proceedings exists, but suggests that the review and potential disallowance of costs during the reconciliation phase of the proposed IRM could be “problematic” because the Commission may be reluctant to disallow the IRM expenditures after they have been incurred. 6 TR 2818-2819. Mr. Coppola provides no support for the claim that the Commission would somehow be reluctant to disallow imprudent spending if it were discovered during an IRM reconciliation proceeding. Mr. Torrey noted in rebuttal:

“The Commission has the ability to approve disallowances of capital dollars spent at any time if found to be unreasonable and not in the interest of customers. Mr. Coppola also fails to recognize that the proposed reconciliation process allows the opportunity for intervenors to review the prudency of actual spending providing customers with certainty that IRM capital work will be performed or refunded.” 2 TR 98.

Hence, the IRM process proposed by the Company actually enhances the incentive for the Company to ensure that the work performed and the costs incurred are prudent in order to withstand the after-the-fact review offered by the IRM reconciliation.

Thus, arguments presented by Mr. Jester and Mr. Coppola that suggest that the Company’s initially proposed IRM does not provide a sufficient prudency review of the capital expenditures included in the IRM should be rejected by the Commission.

c. There Is No Support For The Suggestion That Approval Of An IRM Represents Unsound Regulatory Policy

MEC/NRDC/SC/EC/MEIBC witness Jester, Attorney General witness Coppola, and Kroger witness Justin Bieber all argued that an IRM represents single-issue ratemaking and that single-issue ratemaking is not sound regulatory policy. 5 TR 1398-1400; 6 TR 2608, 2820. Those assertions should be rejected by the Commission. Company witness Torrey explained that capital investments, undertaken by the Company to maintain and improve the safety and

reliability that the Company provides to its customers, have been one of the principal drivers of the Company's need for year-over-year rate case filings. 2 TR 99. An IRM offers the Commission a means to recognize the Company's continuing investments in safety and reliability and also permits the more timely recovery of reasonably and prudently incurred costs. 2 TR 99. Contrary to the claims of MEC/NRDC/SC/EC/MEIBC, the Attorney General, and Kroger, Mr. Torrey explained that an IRM "reduces the regulatory burden for all of the parties involved which is very sound regulatory policy." 2 TR 99. Mr. Torrey also explained that the IRM serves the desire of Consumers Energy's customers to have more predictability in their rates going forward. 2 TR 99. Mr. Torrey testified:

"Many of the Company's business customers have indicated that advanced knowledge of expected rate changes facilitates their own business planning processes. The Company's proposed IRM gives those customers certainty about rates through the beginning of 2022, while also holding rate increases below 2% annually." 2 TR 99.

The IRP provides the opportunity to promote these valid and laudable policy objectives that cannot be achieved through traditional approaches to ratemaking.

Attorney General witness Coppola and Kroger witness Bieber claim that approval of the IRM would reduce the Company's incentive to control capital costs and facilitate over-earning by considering cost increases in one part of the business in isolation while ignoring potential cost decreases in other parts of the business. 5 TR 1398-1399; 6 TR 2820-2821. Mr. Coppola, in particular, characterizes the IRM as a "blank check" to Consumers Energy. 6 TR 2820. However, there is simply no support for the conclusion that an IRM reduces the Company's incentive to reduce capital expenditures. In response to this claim, Mr. Torrey explained once again that an IRM will have a reconciliation process which will subject expenditures to more reasonableness and prudence reviews than currently exist in traditional ratemaking. 2 TR 100.

Since there are additional prudency reviews in an IRM, there is no basis for concern regarding the incentive to contain costs. Furthermore, Mr. Torrey points out that cost recovery during a period of time that the IRM is in effect is capped at the levels proposed in this case. 2 TR 100. Hence, approval of the IRM “would in no way provide a ‘blank check.’” 2 TR 100.

Likewise, there is no support for the argument that an IRM would allow the Company to over-earn in other areas of the business without offsetting the IRM surcharge. First, Mr. Coppola and Mr. Bieber fail to take into consideration that the opposite situation could occur if the Company’s other electric operational expenses are above authorized levels causing earning to fall below authorized levels. Second, their concern is unwarranted because the Commission has the authority to open a proceeding, on its own motion, and require a utility to show cause why its rates should not be reduced if the Company is improperly over-earning. Third, Mr. Coppola and Mr. Bieber fail to acknowledge that the Company’s proposed IRM Excess Return Sharing Mechanism was proposed precisely to address this concern.

Contrary to the claims of the Attorney General’s and Kroger’s witnesses, there are simply no valid policy considerations that militate against approval of the IRM. Any such policy concerns are addressed by safeguard features of the IRM itself, such as after-the-fact prudency review in the reconciliation process and the IRM Excess Return Sharing Mechanism. However, there are valid policy considerations that would be promoted by adopting the IRM. The Attorney General’s and Kroger’s claims to the contrary should be rejected.

d. The Current Case Presents An Ideal Set Of Circumstances To Approve The IRM

Several witnesses filed direct testimony critiquing the Company’s proposal to delay the next rate filing with the approval of the IRM. Kroger witness Bieber asserted that the deferral of a future rate case does not represent a compelling public interest. 5 TR 1400.

MEC/NRDC/SC/EC/MEIBC witness Jester claims that the timing is not right for the Company to stay out of a rate case. He indicates that the EDIIP should be improved sooner than the end of the IRM period and that the IRP may affect the Commission's views concerning required revenue, cost allocation, rate design, and new DR programs. 6 TR 2609-2610. RCG witness Peloquin claims that there are too many unknowns to have a break in rate case filings citing residential rate design being in flux, no definite data on the possible retirement of the Medium 4 coal plants, and the need to continue the gradual reduction in the common equity percentage to 50%. 7 TR 3182.

Mr. Torrey provided rebuttal testimony responding to the various witnesses' claims regarding the value of the proposal to stay out of a new electric rate case until at least spring of 2021. Mr. Torrey testified:

“The opportunity that presents itself with the recently filed EDIIP and modest near-term financial needs may not present itself again for several years. Staff's Michigan Distribution Planning Framework Report dated September 1, 2018, recommends (at page 23) that the next EDIIP be filed in early 2020. This likely means that next opportunity for a multi-year plan tied to a robust electric distribution infrastructure investment plan is at least two years down the road. New rate designs have been implemented before in revenue neutral cases. No coal plant retirements are planned for 2020 or 2021. The potential for a reduction in the equity ratio is offset by the potential for increases in other financing costs such as interest rates related to financial market dynamics beyond Consumers Energy's control. Now is an opportune time for the Commission to approve the IRM proposed by Consumers Energy.”
2 TR 100-101.

This unique opportunity will be lost if the Commission rejects the IRM proposed in this case. As noted in the discussion of the Company's IRM proposal above, it would benefit both customers and the Company by facilitating capital investments needed to improve distribution safety and reliability for customers through the end of 2021, while simultaneously providing timely and modest cost recovery. There may not be a more ideal time in the future for the Commission to

take advantage of the confluence of advantageous circumstances that exist in this case. The Commission should reject the parties' claims regarding the timing of the proposal and approve the Company's IRM.

e. Response To Various Other Criticisms And Conclusion

In addition to the issues discussed above, various witnesses for the other parties offered a small number of other arguments, which attempt to suggest that it would be unreasonable for the Commission to approve an IRM for the Company. None of these arguments have merit and should not serve as an impediment to approving the Company's proposed IRM.

First, Staff witness Laruwe claims that an IRM is only appropriate to address two types of circumstances (i) where there are well-known and measurable safety concerns existing on the system similar to the gas main replacement EIRP currently utilized by Consumers Energy, and (ii) where it is part of a multi-year rate plan that clearly outlines the need for the projected investments, as well as the utility's ability to perform the work both prudently and cost effectively. 6 TR 2274. However, Mr. Torrey points out in his rebuttal testimony that the Commission has already approved cost recovery of programs through an IRM where these two circumstances are not involved. Mr. Torrey explained:

“Consumers Energy’s gas EIRP is one of three significant projects that are part of an IRM approved in Case No. U-18124 and Case No. U-18424. These Commission-approved IRM’s also include significant spending not related to known and measurable safety concerns such as Asset Relocation work. Furthermore, the IRM’s previously approved for Consumers Energy were not part of a multi-year plan as the IRM spending merely repeats approved test year levels rather than reflecting projected spending from a multi-year plan. Therefore, the gas IRMs previously approved for Consumers Energy by the Commission don’t fulfill Mr. Laruwe’s proposed criteria. Staff’s proposed criteria are unduly restrictive. In order to realize the full potential of an IRM, the criteria for including programs in the IRM should be less restrictive than the criteria used for the Company’s gas IRM, not more restrictive.”
2 TR 103.

Mr. Torrey further explained that the IRMs proposed in the Company's gas rate cases are not sufficiently robust to enable the Company to stay out of rate cases for one or more years. 2 TR 103. The Company believes that the Commission shares its desire to find a common sense way to extend the period between rate cases.

Second, Attorney General witness Coppola claims that an IRM surcharge would be confusing and perplexing to customers. 6 TR 2821. But, this claim is also unfounded. Mr. Coppola has provided no record evidence, which provides economic, financial, or customer specific analysis to support the claim that one line item surcharge added to a customer's bill would cause undue burden and confusion. Mr. Torrey points out that the Company has billed an IRM to gas utility customers without causing any confusion for customers. 2 TR 101.

Third, MEC/NRDC/SC/EC/MEIBC witness Jester argues that the IRM should be rejected because it will have a "disproportionate effect on rates for public lighting customers." 6 TR 2589. However, Mr. Torrey points out that, if the IRM is not approved, the Company will need to file a rate case that would include a request for the distribution asset investments needed to serve customers. 2 TR 101. Mr. Torrey explains that customer impacts will be similar whether the IRM is approved or a rate case is filed and the distribution investments are collected through base rates. 2 TR 102. Therefore, this is not a valid reason for denying the Company's request for an IRM.

Finally, ABATE witness Jeffrey Pollock expressed concerns in his direct testimony that the Company's commitment to stay out of a rate case, as expressed in the direct testimony of Mr. Torrey, was not sufficiently strong to provide the parties assurance that they would actually enjoy the benefit of a break in rate cases. 7 TR 3463-3464. In an effort to provide a constructive response to that concern, Mr. Torrey testified:

“On page 35, lines 14 through 22 of my direct testimony, I indicate why the Company may need to file another case prior to February 2021 if the IRM is approved. I would add to that by noting that the Commission has within its authority the ability to approve deferred accounting for items such as catastrophic storms, changes in state or federal energy policy or tax law, the loss of a major customers, or other similar items. Deferred accounting may provide the opportunity to avoid filing a general rate case sooner than February 2021 if such unforeseen events occurred during the IRM period. The Company commits to seeking deferred accounting approval for such items before deciding to file its next general rate case prior to February 2021.” 2 TR 102.

To be very clear, the Company has no design and no desire to secure an IRM consistent with the one proposed in this case only to turn around and file a new rate case in 2019. It would simply be irresponsible for Consumers Energy’s management not to reserve an option to come in for rate relief under circumstances that seriously threaten the financial health of the business. Those circumstances are, for all practical intents, not possible to comprehensively catalogue and define, but that should not be understood to mean that the Company’s commitment to remain out of a rate case is not firm under ordinary circumstances if the IRM proposed by Consumers Energy is approved. The Company has proposed a number of reasonable options to help ensure and provide the parties with confidence that its commitment is real, including the further ideas proposed in Mr. Torrey’s rebuttal testimony in response to ABATE’s fair concern. Having the clarity regarding the Company’s commitment that Mr. Torrey’s direct and rebuttal testimony, as well as this Initial Brief can provide, this issue should not serve as any impediment to the Commission approving the Company’s proposed IRM.

Therefore, for the all of the reasons stated above, the various criticisms of the Company’s IRM offered by the parties should be rejected by the Commission. The Commission should approve the IRM proposed by the Company in this case.

B. Excess Revenue Sharing Mechanism

As discussed above, the Company proposed to implement an IRM Excess Return Sharing Mechanism as a feature of its proposed IRM. Although Staff witness Laruwe recommended that the Commission reject the Company's IRM in its entirety, he nevertheless proposes that the Commission implement an Excess Revenue Sharing Mechanism that would be applicable to the base rates established in reference to the test year in this case. 6 TR 2275-2278. Mr. Laruwe claims that his proposed Excess Revenue Sharing Mechanism is made necessary by what he characterizes as "the need for steps to be taken to address the ongoing excessive earnings" of Consumers Energy. 6 TR 2276. Mr. Laruwe describes the proposed design of his mechanism as follows:

"Staff is proposing a simple mechanism that allows for a 20 basis point dead-band above the authorized ROE (weather-normalized) that would result in no refund to customers. The next 80 basis points would be shared equally between rate payers and shareholder and anything outside 100 basis points would be shared 75% with rate payers and 25% with the Company." 6 TR 2277.

Mr. Laruwe claims that his Excess Revenue Sharing Mechanism will "alleviate concerns with potential future over-earnings by the Company." 6 TR 2276.

For the reasons discussed in the following sections, the Commission should reject Mr. Laruwe's proposed Excess Revenue Sharing Mechanism because it is both unlawful and it would be unreasonable in its effect on the Company's risk profile.

1. Staff's Proposed Excess Revenue Sharing Mechanism Is Unlawful

Staff's proposed Excess Revenue Sharing Mechanism constitutes unlawful retroactive ratemaking and must be rejected. Michigan first adopted the rule against retroactive ratemaking in *Michigan Bell Telephone Co v Michigan Pub Serv Comm*, 315 Mich 533; 24 NW2d 200 (1946). In that case, the Commission issued a December 1944 order requiring Michigan Bell

Telephone Company to reduce its gross revenues by \$3.5 million for the year 1944, and to refund that amount back to customers, based on the Commission's conclusion that certain costs included in rates by the telephone company had been imprudently incurred. *Id.* at 537. After reviewing an extensive body of case law from the United States Supreme Court as well as the courts of several other states, the Michigan Supreme Court concluded that the Commission's order was unlawful. Among others, the Michigan Supreme Court cited approvingly the following holding from *State v Pub Serv Comm of Kansas*, 135 Kan 491; 11 P2d 999, 1006–07 (1932):

“[I]t seems clear that when a rate has been the subject of a deliberate inquiry in which the carriers, the shippers, and the commission's own experts have participated, as well as any and all other persons who cared to take a hand in it as the statute provides and permits (R. S. 66—111 to 66—113), any rate so prescribed by the commission and put into effect by the carriers may be confidently collected and retained by them as their very own, without misgiving that at some future time a further hearing of the commission may be had and more evidence taken and a different conclusion reached and those rates condemned as unreasonable and reparation certificates allowed for the difference between the rates which the commission did authorize and the rates which it should have authorized. Such a method of regulating public utilities has none of the earmarks of due process of law nor of the simplest notions of justice.”

In light of its review of the case law in this and other jurisdictions, the Michigan Supreme Court held, “[W]e cannot find that the commission has either express or implied statutory power to retroactively reduce appellee's rates or its accrued earnings. Instead the commission's rate-fixing orders are effective only prospectively.” *Michigan Bell Telephone Co* at 547 (emphasis added).

The Excess Revenue Sharing Mechanism serves no other purpose than to retroactively reduce Consumers Energy's accrued earnings. That is its specific design. In this case, the Commission has been presented with a considerable amount of evidence that forms the basis of a “deliberate inquiry” into the appropriate rates that should result from this case. Once the Commission sets those rates, they are presumed, *prima facie*, to be lawful and reasonable.

Attorney Gen v Pub Serv Comm, 269 Mich App 473, 479; 713 NW2d 290, 294 (2005). Furthermore, the Company is required by law to charge those rates as it “can claim no right to a rate other than the filed rate either fixed or accepted by the PSC.” *In re Application of Detroit Edison Co*, 276 Mich App 216, 227; 740 NW2d 685, 694 (2007), aff'd in part, rev'd in part sub nom. *In re Detroit Edison Co*, 483 Mich 993; 764 NW2d 272 (2009). Consistent with the Supreme Court’s reasoning in *Michigan Bell*, thereafter, Consumers Energy is entitled to “confidently collect[] and retained” the earnings that result from the application of those rates as the Company’s very own.

In *Detroit Edison Co v Michigan Pub Serv Com’n*, 416 Mich 510, 522-523; 331 NW2d 159 (1982), the Michigan Supreme Court, in considering Detroit Edison’s challenge to a Commission approved Fuel Cost Adjustment Clause, further elaborated on the principles of retroactive ratemaking:

“We think the concern that Edison has not been able to recover all of its costs misses the point. Certainly it is true that in this case Edison's total FCAC charges were less than its excess fuel costs. However, that is simply one of the risks that any utility operating under our regulatory system takes.⁷ Rates are set on the basis of estimates of costs, typically based on a ‘test year’ or other period, which is sometimes adjusted on the basis of predictions as to future trends and events that will affect costs. In the case of Edison's February 1974 rates, the FCAC provided a further device for improving the estimates on which the billings were based. But the essential principle of the rule against retroactive ratemaking is that when the estimates prove inaccurate and costs are higher or lower than predicted, the previously set rates cannot be changed to correct for the error; the only step that the MPSC can take is to prospectively revise rates in an effort to set more appropriate ones.”

⁷ Of course, the utility faces a corresponding ‘risk’ of overcollection should costs fall. *Cf. Michigan Bell Telephone Co. v. Public Service Comm., supra.*”

(Emphasis added; footnotes 8 through 10 omitted).

Ratemaking is not, nor has it ever been, a precise mathematical exercise that results in perfect recovery of a utility's actual costs in hindsight – no more, no less. See, e.g., *In re Consumers Energy Co*, 322 Mich App 480, 487; 913 NW2d 406, 412 (2017) (“The establishment of a reasonable utility rate is not subject to precise computation”). As the United States Supreme Court has stated:

“The economic judgments required in rate proceedings are often hopelessly complex and do not admit of a single correct result Errors to the detriment of one party may well be canceled out by countervailing errors or allowances in another part of the rate proceeding.” *Duquesne Light Co v Barasch*, 488 U.S. 299, 314; 109 S Ct 609; 102 L Ed 2d 646 (1989).

Instead, the goal of ratemaking is to approximate, in a reasonable manner, the costs that a utility is expected to incur during the period of time that rates will be in effect, with an allowance to permit the utility the opportunity to earn a reasonable return on its capital devoted to the public's use. *Hope*, 320 US at 603.

However, the Excess Revenue Sharing Mechanism proposed by Staff in this case seeks to correct for the inherent imprecision of prospective ratemaking in order to ensure that the resulting earnings of the Company do not deviate from the returns assumed in setting the rates, but only to the extent that the result would be beneficial to the utility. Under cross-examination, Staff witness Laruwe was asked to elaborate on what concern he was trying to address through his proposed Excess Revenue Sharing Mechanism. Mr. Laruwe stated:

“I would say my concerns lie with I think there's an obligation for the Company not to only project prudent expenditures, but to also operate prudently during the operation of a projected test year, and in order to understand the operations during the test year, it's important to look at what those variations were and examine them for prudence, because although they did differ from what was ultimately approved by the Commission in the previous order, I don't think that the obligation to act prudently during the operation of a projected test year is diminished.” 6 TR 2297.

The Company does not dispute that it continues to have an obligation to manage its business prudently during the future periods of time that comprised the test year in a previous rate case. The Company further recognizes that its past management decisions will be properly considered by the Commission and Staff in making any future, forward-looking rate determinations. However, Mr. Laruwe is proposing to use an after-the-fact prudency review of the Company's spending to adjust the past earnings of the Company. Mr. Laruwe testified that "I believe the excess earnings mechanism would also protect customers from the utility seeing financial windfalls when their forecast turns out to be inappropriate or inaccurate, along with when economic conditions that are outside their control seem to benefit them financially" 6 TR 2299. That is exactly what the rule against retroactive ratemaking does not permit. As the Michigan Supreme Court noted, "when the estimates [used to make rates] prove inaccurate and costs are higher or lower than predicted, the previously set rates cannot be changed to correct for the error." This process is fair, in part, because the risks to both the Company and the customers are congruent. Although Mr. Laruwe points to a handful of recent years in which the Company's actual earned ROEs for its electric business have been higher than the ratemaking ROEs used by the Commission, he fails to acknowledge the fact that, in the majority of years over the last decade, the Company's weather normalized earned ROEs have more frequently been less than the ROE assumed in setting rates. See 2 TR 352.

In *Michigan Bell*, the Michigan Supreme Court established its prohibition on retroactive ratemaking based on the grounds that the Michigan Legislature had not delegated power to the Commission to give its rate orders retroactive effect. 315 Mich at 551. The Court also recognized that there may also be a constitutional concern that such retroactive ratemaking would deprive a utility of its property without due process of law. *Id.* at 555. However, having

decided the issue on statutory grounds, the Michigan Supreme Court elected to defer determination of the constitutional issue to a later case. *Id.* In *Northern Michigan Water Co v Mich Pub Serv Comm* 381 Mich 340, 353; 161 NW2d 584 (1968), the Michigan Supreme Court held that it was unlawful for the Commission to order utilities (in this case, water utilities) to issue refunds from rates that had been previously approved as lawful by the Commission. (“Here, the commission approved the plaintiff’s Mohawk rate as reasonable and lawful. That being the case, there was no basis upon which it could order a refund.”). Again, the Court noted the potential unconstitutionality of such retroactive refunds, but did not expressly decide the issue (“Neither do we address ourselves to the effect of section 18, P.A.1967, No. 19, on these proceedings. If the rates involved were legal when charged, the Act would be unconstitutional.”). *Id.* at 350. However, other jurisdictions that have expressly addressed the issue of the constitutionality of this type of retroactive refund of a utility’s earnings have concluded that such refunds are constitutionally impermissible as well. See, e.g., *Straube v Bowling Green Gas Co*, 360 Mo 132; 227 SW2d 666 (1950) (“The money legally and properly collected from appellants under the established rate schedules became and was the property of respondent. When the established rate of a utility has been followed, the amount so collected becomes the property of the utility, of which it cannot be deprived by either legislative or judicial action without violating the due process provisions of the state and federal constitutions.”). In addition to being a violation of Michigan’s rule against retroactive ratemaking, the Company submits that the Excess Revenue Sharing Mechanism proposed by Staff witness Laruwe would also violate the Company’s constitutional rights under the due process clauses of the state and federal constitutions.

Finally, the Company submits that the Excess Revenue Sharing Mechanism proposed by Staff may also constitute an unlawful Revenue Decoupling Mechanism (“RDM”). The goal of an RDM is to break the link between a utility’s energy sales and its non-fuel revenues. See, e.g., MPSC Case No. U-15985, June 3, 2010 Order, page 75. Traditionally, the Commission has authority to regulate the *rates* and *charges* of an electric utility. MCL 460.6(1); 460.552. The Commission, strictly speaking, does not regulate an electric utility’s *revenues*. The Commission’s authority to regulate the revenues of a utility is an indirect authority in the sense that the Commission makes a determination regarding the appropriate level of revenues necessary for a utility to recovery its costs and earn a reasonable return in order to thereafter calculate just and reasonable rates. However, revenue decoupling modifies that traditional paradigm in order to provide a regulatory body more direct authority to establish revenues and not merely rates. That is exactly what Staff’s proposed Excess Revenue Sharing Mechanism seeks to accomplish, albeit in the form of a one-way RDM that only operates if the resulting revenues become too high, but not if they are too low. However, *In re Detroit Edison Co Application*, 296 Mich App 101, 108; 817 NW2d 630, 633 (2012), the Michigan Court of Appeals held that the Commission exceeded its statutorily granted authority when it authorized Detroit Edison Company to adopt a RDM for its electric business.

Although the Commission may not lawfully impose a refund on a utility in violation of the rule against retroactive ratemaking, it is important to note that the courts have recognized a utility’s right to voluntarily consent to a refund that the Commission may not otherwise lawfully impose upon it. See e.g., *Attorney Gen v Michigan Pub Serv Comm*, 206 Mich App 290, 297; 520 NW2d 636, 640 (1994) (holding that a Commission-approved settlement agreement whereby Consumers Power Company agreed to a one-time refund of earnings above 13.25% in 1992, did

not constitute retroactive ratemaking because it was “consensual.”). See also *ABATE v Michigan Pub Serv Comm*, 205 Mich App 383, 388; 522 NW2d 140 (1994). As indicated in the direct testimony of Company witness Torrey, Consumers Energy is willing to voluntarily consent to the IRM Excess Returns Sharing Mechanism in connection with an approved IRM that is consistent with the one proposed by the Company in this case. The Company will not voluntarily consent to the Excess Revenue Sharing Mechanism proposed by Staff witness Laruwe in this case.

For all of the foregoing reasons, the Excess Revenue Sharing Mechanism proposed by Staff witness Laruwe is unlawful. The Commission should reject Staff’s proposal to impose such a mechanism on the rates established for the test year in this case.

2. Staff’s Proposed Excess Revenue Sharing Mechanism Is Unreasonable

Even if the Excess Revenue Sharing Mechanism proposed by Staff were lawful, it would be unreasonable to apply it to the Company in this case. Company witness Maddipati expressed several practical concerns that demonstrate that the mechanism should not be adopted in a traditional ratemaking environment.

Mr. Maddipati provided rebuttal testimony pointing out that Mr. Laruwe relied principally on materials related to performance-based ratemaking approaches in developing his recommendation. 3 TR 552. According to Mr. Maddipati, Staff’s proposed Excess Revenue Sharing Mechanism is an attempt to cherry-pick one component of a performance-based ratemaking mechanism and insert it into rates set through a traditional cost-of-service model without including any of the other associated pieces of a performance-based ratemaking approach.²³ 3 TR 552. Mr. Maddipati testified:

²³ It should also be noted that, in states that have included some type of excess revenue sharing mechanism as a feature of a multi-year or performance-based ratemaking approach, the utility’s participation has generally been

“The Company is not aware of, and Mr. Laruwe did not provide in his testimony any examples of a jurisdiction that has imposed an earnings sharing mechanism absent some multi-year rate plan. On page 10 of his testimony, Mr. Laruwe suggests that the appropriate use of an IRM is in connection with a multi-year rate plan, yet he fails to recognize the appropriate use of an earnings sharing mechanism is with a multi-year rate plan.” 3 TR 552.

In the context of the Company’s proposed IRM, an Excess Revenue Sharing Mechanism makes sense and balances some of the adverse impacts of such a mechanism on utilities with offsetting benefits that make the combined proposal reasonable for the utility and customers alike. However, taken out of that context, the Excess Revenue Sharing Mechanism creates adverse impacts on the Company’s credit and risk profile with no offsetting benefits. Mr. Maddipati further cites the Commission’s own findings in its performance-based ratemaking report, wherein the Commission states:

“Such transformative changes would not be made **to the entire regulatory paradigm overnight**; the Commission is more inclined to test the efficacy of PBR through specific natural gas and electric utility pilot programs or other targeted opportunities. This study has demonstrated that **incorporation of a public process with stakeholders and utilities is important** to the success of new and innovative programs.’ *MPSC Report on the Study of Performance-Based Regulation*, page 24.” 3 TR 553 (emphasis added in testimony).

This case is not presented under a performance-based ratemaking approach, and it would be premature and inappropriate to attempt to impose performance-based ratemaking concepts haphazardly into a traditional rate case. The Commission’s own exploration of the potential for performance-based ratemaking is still nascent, and the measured approach proposed by the

consensual. See e.g., GA Code Ann § 46-2-23.1 (Georgia statute making participation in a performance-based ratemaking approach optional); *In re Citizens of State of Florida*, 1999 WL 691966 (1999) (Docket No. 990067) (Florida Public Service Commission order approving a settlement agreement establishing a multi-year rate plan with revenue sharing mechanism); and *In re Idaho Power Co*, 1995 WL 735564 (1995) (Case No. IPC-E-95-11) (Idaho Public Utilities Commission order approving a settlement agreement establishing a multi-year rate plan with revenue sharing mechanism). Again, as discussed in the preceding section, imposing such a mechanism on a utility involuntarily would constitute unlawful retroactive ratemaking and would violate constitutional due process rights.

Commission to develop and test the efficacy of performance-based ratemaking model in Michigan is prudent.

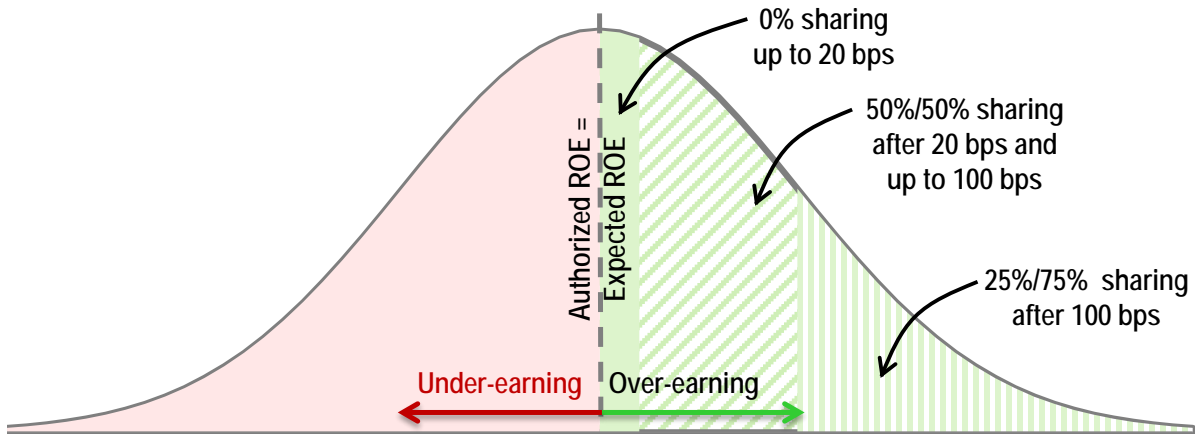
As noted above, the most significant problem with Excess Revenue Sharing Mechanism proposed by Staff is that it would have an adverse credit impact on the Company. Under traditional ratemaking approaches, there is a relationship between the Company's authorized ratemaking ROE and its eventual earned ROE. 3 TR 540. While the utility's earned ROEs may not exactly match the ratemaking ROE in any given year based on any number of different circumstances, the probability of under-earning or over-earning is equally and symmetrically distributed about the ratemaking ROE because a utility's ratemaking ROE is the mechanism that establishes the utility's opportunity to earn its ROE. This is illustrated in Figure 5a from Mr. Maddipati's rebuttal testimony reproduced below. 3 TR 555.

Before Sharing Mechanism: Symmetric Outcomes (Figure 5a)

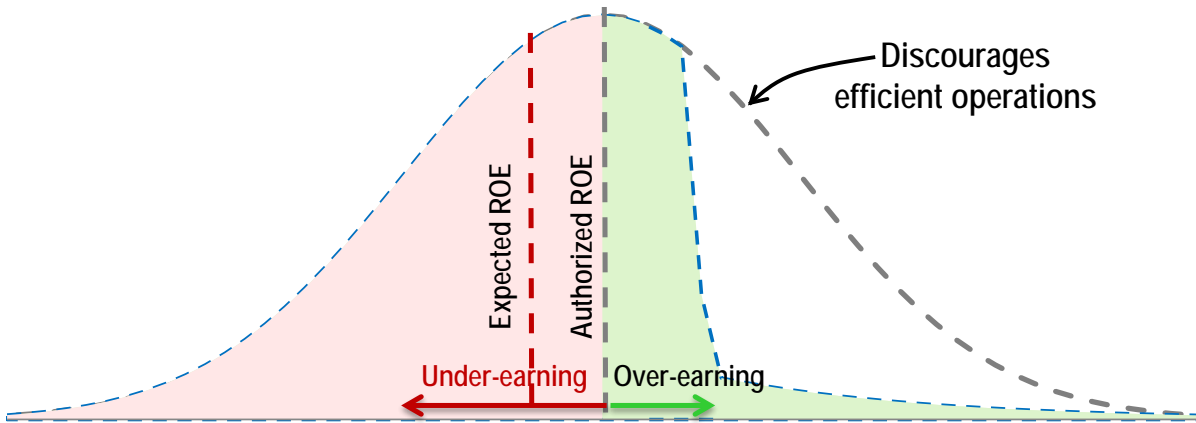


However, the Excess Revenue Sharing Mechanism proposed by Staff has the effect of eliminating the symmetry. The result is that it skews the likely outcome toward under-earning, which meaningfully changes the risk profile of the Company. This is illustrated in Figures 5b and 5c from Mr. Maddipati's rebuttal testimony reproduced below. 3 TR 555.

Proposed Sharing Mechanism: Asymmetric Risk to Investors (Figure 5b)



After Sharing Mechanism: Outcomes Skewed Toward Under-earning (Figure 5c)



Mr. Maddipati testified in his rebuttal testimony that Staff failed to perform any analysis to ensure they the proposed Excess Revenue Sharing Mechanism would support the credit of the Company. He testified:

“When asked in discovery, Mr. Laruwe indicated he had not done any analysis to ensure that the earning mechanism proposed would support the credit of the Company. Mr. Megginson was also asked in discovery if he had done any analysis of Mr. Laruwe’s mechanism to ensure it supports the credit of the Company, to which he responded no. While Mr. Megginson claims that his ROE analysis factored in the Company’s credit metrics, he fails to

consider the fact that Mr. Laruwe's mechanism would have an impact on the likelihood of the Company actually achieving the ROE which he claims would support the credit of the Company. Mr. Megginson seems to believe his ROE analysis can be conducted independent of Mr. Laruwe's recommendation, which it cannot. Absent an analysis of whether the proposed mechanism supports the Company's credit, the Commission should give Mr. Laruwe's testimony little weight." 3 TR 556.

Likewise, Mr. Maddipati points out that neither Mr. Laruwe nor Mr. Megginson performed any analysis to ensure that the Excess Revenue Sharing Mechanism would continue to allow the Company to have access to capital on reasonable terms. 3 TR 556-557. The Company's ability to earn its ratemaking ROE is a key consideration reflected in all of the reports produced by credit rating agencies and equity research analysts relative to Consumers Energy. See, e.g., 3 TR 420-421. It is reasonable to conclude that these analysts will view any mechanism that increases the risk of under-earning ROE and asymmetrically eliminates the corresponding possibility of over-earning as having a detrimental impact on the Company's financial strength.

As a result, the Excess Revenue Sharing Mechanism proposed by Mr. Laruwe is also inconsistent with the financial models used by Mr. Megginson to calculate a proposed ROE in this case. Mr. Maddipati testified:

"One of the assumptions of these models is that expected returns are symmetrical . . . , however as discussed, Mr. Laruwe's proposal would allow returns above the authorized ROE to be shared but provides no mechanism to share downside risk in the event the earned ROE were lower than authorized – which is inconsistent with the assumptions of the models used by Mr. Megginson." 3 TR 557.

Given these impacts on the Company's credit and risk profile, it would not be reasonable to impose Staff's Excess Revenue Sharing Mechanism on the Company, even if it were lawful to do so.

The Commission should reject Staff's proposal to apply an Excess Revenue Sharing Mechanism to the Company's base rates established relative to the test year in this case. As proposed by the Company, a mechanism such as this should only be applied in the context of a multi-year ratemaking approach, like the IRM, where there exist offsetting benefits to mitigate the detrimental impact of such a mechanism on the Company's credit and risk profile.

C. CSXT Litigation Cost Recovery

1. Company Position

Company witness Blumenstock addressed the Company's request to recover certain costs incurred by the Company in the litigation of its successful rate complaint against CSX Transportation ("CSXT") before the Surface Transportation Board ("STB"). 5 TR 1448-1454. Specifically, Mr. Blumenstock explained that, in mid-2013, the Company began efforts to replace its bilateral contract with CSXT for rail transportation that was set to expire on December 31, 2014. 5 TR 1448. However, in evaluating its contract with CSXT, it was determined that CSXT's coal transportation rates to the Campbell Plant were disproportionately higher than rates in the Company's other coal transportation contracts and higher than the rates that other utilities in the Midwest paid. 5 TR 1448. The primary contributor to the high rates is the fact that the Campbell Plant is "captive" to CSXT (meaning that there are no other coal transportation alternatives to the Campbell Plant, and that CSXT is the sole provider of rail transportation to the site). 5 TR 1448. After over a year of negotiations and efforts by the Company to establish reasonable, cost-based rates for the Campbell Plant, negotiations reached an impasse and the only alternative available to the Company was to challenge the rates before the STB. 5 TR 1448-1449.

On January 13, 2015, Consumers Energy filed a complaint with the STB against CSXT in STB Docket No. NOR 42142. 5 TR 1449. In its complaint, the Company argued that the

transportation rates set by CSXT for the transport of coal from Chicago, Illinois, to the Campbell Plant to be excessive, arbitrary, and detrimental to Consumers Energy's customers. The complaint requested that the STB: (i) find the challenged rates to be unreasonable and unlawful; (ii) prescribe lawful rates; (iii) award damages to Consumers Energy; and (iv) grant Consumers Energy any further relief as the STB may deem proper. 5 TR 1449.

On January 11, 2018, the STB decided in favor of Consumers Energy, deciding that the Company had no alternative shipping options other than CSXT. Consequently, the rates CSXT charged, as challenged by the Company, were found by the STB to be "unreasonably high under the stand-alone cost restraint." Docket No. NOR 42142, Digest, page I, January 11, 2018, Decision. 5 TR 1449. The STB also established parameters to calculate "reasonable" rates on a go-forward basis, and identified reparations for past, excessive charges. 5 TR 1449. Furthermore, on August 2, 2018, the STB entered its decision on the Company's Petition for Technical Corrections filed in February 2018. Mr. Blumenstock explained that, in that decision, the STB sided with the Company on several of the identified technical corrections and further increasing the expected rate reductions and reparations to be received by Consumers Energy's customers. 5 TR 1460.

Based on the above litigation before the STB, Mr. Blumenstock explained that the actual and forecasted litigation expenses are currently \$7,493,073 and \$380,000, respectively. 5 TR 1460. Additionally, after the STB's August 2, 2018 decision, total customer savings are valued at \$132,524,305 and reparations have increased to \$24,048,546. This is provided in Exhibit A-135 (RTB-5), column (g), line 11 and column (d), line 11. Mr. Blumenstock also explained that the Company's customers have already received savings from reduced rail rates in 2018 in the amount of \$2.8 million, and will continue to receive the benefit of reduced rates

going forward. 5 TR 1460. Mr. Blumenstock not only addressed the monetary benefits to the Company's CSXT litigation efforts but also addressed how these benefits will be passed to customers as follows:

“The beneficiary of these filings remains the Company's PSCR customers. Since coal transportation expense is a direct pass through to PSCR customers, any reduction in coal transportation expense resulting from the positive outcome in the CSXT litigation effort will entirely and directly benefit the Company's PSCR customers.

“Additionally, any reparations that are awarded to the Company from CSXT as a result of the positive outcome in the litigation effort will be passed through in their entirety to the Company's PSCR customers. The Company receives no benefit to undertaking this effort, other than to ensure it is taking prudent actions to minimize the cost of fuel to its customers.” 5 TR 1453.

Mr. Blumenstock also indicated that the Company originally requested to recover these costs through the PSCR because the litigation effort was undertaken on behalf of the Company's PSCR customers. 5 TR 1451. The Company planned to seek recovery of the litigation expense in the respective PSCR year that the litigation expense was incurred, or expected to be incurred and filed requests for approval in the 2016 PSCR Plan, Case No. U-17918, the 2015 PSCR Reconciliation, Case No. U-17678-R, and the 2017 PSCR Plan, Case No. U-18142. 5 TR 1451. However, on October 11, 2016, the Commission found that the Company's CSXT litigation costs were not appropriate for inclusion in the 2016 PSCR Plan, Case No. U-17918. 5 TR 1452. The Commission indicated: “The recovery of this type of expense is more suitable in a rate case.” See MPSC Case No. U-17918, October 11, 2016 Order, page 30. The Commission made a similar finding in its February 5, 2018 Order in the Company's 2017 PSCR Plan, Case No. U-18142.

Since the Commission has indicated that the Company's request to recover the CSXT litigation expense is more suitable in a rate case, the Company is requesting the recovery of these expenses in this case. Specifically, the Company proposes recovery of the CSXT litigation expense through the use of a surcharge that will be assessed to full-service customers. 5 TR 1577. As shown on Exhibit A-69 (LMC-6), the Company is proposing to recover the CSXT litigation expense through the use of a surcharge assessed to Full Service customers during the March 2019 to August 2019 bill months. 5 TR 1577.²⁴

The Company also proposed an alternative collection method to the surcharge method discussed above. 5 TR 1453-1454. If the Commission does not approve recovery of the CSXT litigation expenses through the proposed surcharge, the Company proposes that the reparations identified on Exhibit A-135 (RTB-5), column (d), line 11, be offset by the total litigation expense incurred by the Company on behalf of customers. 5 TR 1453-1454. The Company proposes that the remaining reparations amount, after subtracting litigation expenses, be credited to customers in the next PSCR proceeding filed after the conclusion of this rate case. 5 TR 1454. The portion of the reparations amount retained by the Company would serve as compensation for the litigation expense. 5 TR 1454.

2. Reply To ABATE

ABATE witness Pollock opposes the Company's recovery of CSXT litigation expense. In an attempt to support this position, Mr. Pollock offers a litany of criticisms which include: (i) an assertion that the new transportation rates have not been implemented, and therefore the benefits of the new rates have not been realized; (ii) the assertion that the Company's CSXT litigation expense is not recoverable as a special item because it is an expense the Company

²⁴ Please note that Exhibit A-69 (LMC-6) serves as an illustration of the proposed surcharge. However, the actual surcharge amount must be updated to reflect the totals on Exhibit A-135 (RTB-5).

normally incurs; and (iii) the assertion that the Company's litigation expense is not material compared to total O&M spending. 7 TR 3466-3470. These criticisms should be rejected because they fail to support the rejection of the Company's proposed recovery in this case.

Contrary to Mr. Pollock's first claim, the benefits of lower transportation rates have already been realized by customers. Mr. Blumenstock explained that CSXT corrected its rates in February 2018 as a result of the STB's January 11, 2018 decision and again corrected its rates in August 2018 as a result of the STB's August 2, 2018 decision. 5 TR 1463. Furthermore, as explained above and shown in Exhibit A-135 (RTB-5), customers are already experiencing a \$2.8 million annual rail rate reduction. 5 TR 1463. Not only have savings already been realized by customers in the form of reduced rail rates, but reparations are also certain to be realized. 5 TR 1463. The magnitude of these reparations, which are calculated to be \$24,048,546, is well above litigation expenses. 5 TR 1463.

Mr. Pollock is also incorrect that the CSXT litigation expense is akin to the other types of litigation and outside service expense that the Company routinely incurs. Mr. Blumenstock explained that the general litigation and outside service expense pertains to efforts made for the benefit or protection of the Company. 5 TR 1463. However, the CSXT litigation effort, and corresponding expense, was undertaken solely on behalf of customers. 5 TR 1463. Mr. Blumenstock further clarified that, particularly in this case, the cost of the CSXT litigation was incurred specifically to ensure that customers were not getting unnecessarily or unfairly overcharged for a necessary commodity, and to recapture that overcharge directly for customers. 5 TR 1464. Furthermore, Mr. Blumenstock explained that while the Company does endeavor to ensure the lowest possible power supply costs, the litigation of a complaint at the STB is an extraordinary and non-routine occurrence. 5 TR 1464.

Moreover, Mr. Pollock is incorrect in his assertion that the Company's CSXT litigation expense is not material. Mr. Pollock points out that the CSXT litigation expense is small when compared to the total amount of O&M spent by the Company. 7 TR 3468. However, Mr. Pollock's observation is irrelevant to the recoverability of the CSXT litigation expense. 5 TR 1464. The size of a proposed expense or expenditure presented in this case does not have a bearing on whether or not that proposed expense or expenditures was or will be reasonably and prudently incurred. Additionally, as pointed out by Mr. Blumenstock, "amounts much less than [the CSXT litigation expense] are commonly the subject of scrutiny in electric rate case." 5 TR 1464. The record evidence in this case overwhelmingly establishes that the Company's litigation efforts were undertaken solely for the benefit of customers and the Company ultimately achieved significant customer benefits in the form of reduced rates and reparations.

Therefore, for the reasons discussed above, and explained in more detail in the testimony and exhibits sponsored by Company witness Blumenstock in this proceeding, the Commission should reject Mr. Pollock's recommendation and approve the recovery of the Company's CSXT litigation expense.

3. Reply To The Attorney General

Attorney General witness Coppola opposes the Company's proposal to collect the CSXT litigation expense through a surcharge. 6 TR 2873. However, Mr. Coppola does support the Company's alternative cost recovery proposal of retaining a portion of the reparations ordered by the STB to recover all or a portion of the costs incurred for the CSXT litigation. 6 TR 2874-2875. The following addresses Mr. Coppola's criticisms and recommendation.

While the Company does not take issue with Mr. Coppola's ultimate recommendation that recovery of the CSXT litigation expense can be achieved through netting the expense against the reparations, the Company does oppose numerous conclusions presented by Mr. Coppola in

his testimony. The first of such conclusions is Mr. Coppola's assertion that there is no assurance that the rate savings ordered by the STB will actually be realized. This is incorrect. As shown in Exhibit A-135 (RTB-5), the Company's customers have already received \$2.8 million in savings due to rate reductions implemented by CSXT following the STB's decisions in January and August of 2018. 5 TR 1461. Mr. Blumenstock also explained that customer savings due to reduced rail rates will continue to be realized throughout 2018 and through 2024, the period that was the subject of the STB's decision. 5 TR 1461.

Mr. Coppola is also incorrect that the Company's recovery of litigation expense is premature since the litigation is allegedly still ongoing. Mr. Blumenstock explained that, contrary to Mr. Coppola's claim, customer savings related to the Company's litigation efforts are certain. 5 TR 1461. This is in part demonstrated by the \$2.8 million customers have already received and the statement from the STB that they estimate customer savings to be approximately \$94.9 million.²⁵ 5 TR 1461. Furthermore, while litigation in the form of appeals from the STB's January 2018 and August 2018 decisions may be ongoing, the savings estimates developed by the Company and the STB demonstrate that the transportation rate reductions achieved by the Company's efforts are well in excess of the estimated litigation expense incurred by the Company on behalf of customers.

While the Company does take issue with certain assertions made by Mr. Coppola, the Company does agree with Mr. Coppola that "it is important to allow the Company the opportunity to recover a portion or all of the litigation costs up to achieved cost savings in order to provide a purposeful incentive to litigate matters or negotiate a favorable outcome for

²⁵ While this amount is lower than the amount provided in Exhibit A-135 (RTB-5), the STB's representation of savings should be seen as a baseline of potential savings and not a cap on savings. Further savings could be realized through the appeals process.

customers pertaining to power supply costs.” See 6 TR 2874; 5 TR 1462. The Company also agrees with Mr. Coppola’s recommendation for the Commission to approve the alternate method of recovering CSXT litigation expense, which involves the Company retaining an amount of the reparations paid by CSXT to cover the litigation expense and then refunding the remainder to customers. 6 TR 2875; 5 TR 1462. This alternative approach is not only reasonable but also addresses both Mr. Coppola and Mr. Pollock’s concern about premature cost recovery. 5 TR 1462.

D. State Reliability Mechanism Calculation

Company witness Blumenstock provided the State Reliability Mechanism (“SRM”) capacity cost offsets and demand. 5 TR 1439-1443. This information was used by Company witness Josnelly C. Aponte to develop the SRM Net Capacity Cost which is needed to derive the SRM Capacity Charge for the 2019/2020 Planning Year. Mr. Blumenstock provided the capacity offsets at 5 TR 1440 and the capacity charge demand value at 5 TR 1443.

Energy Michigan witness Zakem and ABATE witness Pollock both asserted in their respective direct testimonies that the Company’s SRM Capacity Charge did not align with the methodology approved by the Commission in Case No. U-18239. 7 TR 3151; 7 TR 3502. The Company agreed with the criticism of Mr. Zakem and Mr. Pollock concerning alignment with the Commission’s Order in Case No. U-18239. 5 TR 1457. However, the Company does not agree with the denominator used by Mr. Zakem and Mr. Pollock in their calculations. 5 TR 1457. Mr. Blumenstock explained the correct denominator to use in the SRM calculation as follows:

“The denominator of the SRM Capacity Charge represents the amount of capacity that is the basis for the fixed costs in the numerator of the SRM Capacity Charge. The Company takes exception with the denominator of the SRM Capacity Charge

being sourced from the Company's most recent Securities and Exchange Commission ('SEC') Form 10-K filing; rather, it should be sourced from the Power Supply Cost Recovery ('PSCR') Forecast sponsored in my direct testimony (Exhibit A-33 RTB-1), and submitted as part of this case for the 2019 test year.

"The Company takes further exception with the denominator of the SRM Capacity Charge representing the maximum tested capacity of all Company resources as it is captured in the SEC Form 10-K filing; rather, it should represent the amount of Zonal Resource Credits ('ZRCs') assigned to the Company's capacity resources by Midcontinent Independent System Operator, Inc. ('MISO') under its Resource Adequacy construct¹. ZRCs are a measure of a resource's available capacity after discounting for the resource's effective forced outage rate. Under MISO's Resource Adequacy Construct, one ZRC is sufficient to serve one MW of demand.

¹ See MISO Resource Adequacy Business Practice Manual, BMP 011-r18, Effective Date January 22, 2018." 5 TR 1457-1458 (footnote 2 omitted).

The Company is therefore proposing to use the PSCR information, as provided in Exhibit A-33 (RTB-1), as the source of the SRM Capacity Charge denominator. 5 TR 1458. The Company also proposes to use Zonal Resource Credits ("ZRC") values in that calculation 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 Planning Reserve Margin Requirement. 5 TR 1458. The use of SEC Form 10-K filing information to calculate the SRM Capacity Charge, as proposed by Mr. Zakem and Mr. Pollock, is not appropriate since it (i) does not represent the Company's plans for the test year that is the subject of this proceeding, and (ii) does not reflect the ZRC value of the Company's generating resources.

Using the PSCR forecast, as provided in Exhibit A-33 (RTB-1), and units of ZRCs for the Company's capacity resources, the revised denominator of the SRM Capacity Charge is 8,336. 5 TR 1459. The details of this calculation are shown in Exhibit A-134 (RTB-4). Furthermore, using Ms. Aponte's "Net Capacity Cost" of \$1,022,286,000 in Exhibit

A-30 (JCA-3), line 19, and the revised denominator of the SRM Capacity Charge stated above, the SRM Capacity Charge is \$335.99 MW/Day. 5 TR 1459.

E. EV Program And Regulatory Asset

Company witness Michael J. Delaney presented the Company's proposal for a three-year Pilot Foundational Infrastructure Program (the "Pilot Program") to support the growing EV market in the Company's electric service territory.

Mr. Delaney began his testimony by providing information regarding the status of the EV market. Based on research, he indicated that there are approximately 4,000 EVs in the Company's electric service territory, and indicated that forecasts estimate that EV sales will result in growth between 150,000 EVs in Michigan by 2030 based on historical sales data, and 800,000 EVs in Michigan by 2030 based on forecasts by Bloomberg New Energy Finance. 4 TR 1030-2031. With transportation electrification in Michigan being in its initial stages, Mr. Delaney explained that there are barriers around EV adoption, including barriers involving customer awareness and knowledge of EVs, and range anxiety due, in part, to geographical gaps in charging infrastructure. 4 TR 1031. While these barriers exist, EV ownership presents multiple benefits to the public, as discussed at a technical conference held by the Commission on August 9, 2017, in Case No. U-18368. One of those benefits, as Mr. Delaney described, involves customer rates. He explained, "from a regulatory perspective, increased EV adoption puts downward pressure on electric rates by spreading fixed costs over increased electric load which would ultimately reduce electric rates for all customers." 4 TR 1031. Getting to a position where ratepayers are benefitted, however, involves the evaluation of numerous issues ranging from barriers to EV adoption, to the impacts of EV growth on the electric grid and, ultimately, how Consumers Energy plays a role in each of those components. Mr. Delaney

explores the impacts of EVs on the electric grid, barriers to EV adoption, the role of the Company in supporting EV growth, proposed rates for EVs, and, with that information, he explains the proposed Pilot Program, PowerMIDrive.

1. Preliminary Issues In The Evaluation Of EVs And The Pilot Program

Along with the collection of information regarding forecasts related to growth in the EV market in Michigan and in the Company's electric service territory, a number of other issues were evaluated by the Company in the preparation of the proposed Pilot Program in this matter. Included in that evaluation was an initial analysis of the impact of EVs on the electric grid, barriers to EV adoption, the role of Consumers Energy in supporting EV growth, and a rate design that will be well suited to EV ownership.

First, Mr. Delaney recognized that EVs can be a benefit, or a burden, to the grid depending on vehicle charging. 4 TR 1032. He explained that “[a]n unprepared grid will be burdened by increased load demand at peak times, such as when drivers return home in the evening.” 4 TR 1032. Thus, he suggested, “[a] grid prepared with smart charging and Time of Use (‘TOU’) rates can adjust EV loads to off-peak hours, optimizing the grid and benefitting all utility customers.” 4 TR 1032. While, as Mr. Delaney explained, in the short term, a small amount of EV growth might not significantly impact the aggregate residential power demand, further analysis is needed to determine the impacts on the Company's territory in the future, which will be an analysis included in the Pilot Program. 4 TR 1032-1033.

Second, Mr. Delaney addressed the issue of range anxiety. As he explained, “[l]imited availability and geographic distance between chargers, lack of EV understanding, and desire for a vehicle with a significantly higher range than average daily mileage all lead to range anxiety.” 4 TR 1033. This range anxiety can be partially alleviated by installing charging infrastructure

and educating customers about charging capabilities and their own driving needs. 4 TR 1033. Thus, Michigan's infrastructure gap and a similar gap in EV owner education must be and will be addressed in the Pilot Program.

Finally, Mr. Delaney explained that Consumers Energy can support EV growth by investing in EV infrastructure and proactively testing methods to encourage off-peak charging, implement smart charging, and increase system utilization. 4 TR 1034-1035. As Mr. Delaney testified:

“Taking time to test methods and develop data infrastructure to support and manage EVs will help avoid a more sudden (and possibly larger) infrastructure spend to meet charging demands of uncontrolled EV load when many more EVs are on the road. Grid-beneficial actions will not happen without proactive effort on the part of Consumers Energy to encourage off-peak charging, implement smart charging, and increase system utilization. This [Pilot] Program is designed to test approaches while overall EV adoption is still low.” 4 TR 1034-1035.

To complement this approach, Mr. Delaney explained:

“Consumers Energy, like other utilities, is uniquely suited to improve the customer experience and facilitate the realization of benefits associated with EV adoption Consumers Energy can leverage its role as a trusted source of information, with existing data on daily home energy use, to develop an informed market and grow customer confidence in EV technology. Consumers Energy like other utilities, can also offer rate options and incentives to influence charging behavior, and ensure that the expertise accumulated from pilots and programs will benefit all utility customers. The added benefit of addressing EV customers' current obstacles with range anxiety and awareness is that through the Program, the Company will learn valuable lessons about how to better serve customers.” 4 TR 1035-1036.

To that end, Mr. Delaney introduced the idea of a tariff rate specific to EVs, as developed by Company witness Laura M. Collins, called the Nighttime Savers Rate. 4 TR 1036. The assumptions built into this program, and the expected benefits are detailed in Exhibit A-74 (MJD-2).

2. Evaluation Of Pilot Program: PowerMIDrive

The objective of the Pilot 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. 4 TR 1039. PowerMIDrive is designed to seed the EV market in Consumers Energy's electric territory with an initial infrastructure investment that will enable Michigan drivers to own and use EVs by enabling residential charging, Level 2 public charging, and Direct Current Fast Charging ("DCFC") across Consumers Energy's territory. 4 TR 1039. The Company plans to approach this with an emphasis on learning by tracking utilization through at-the-meter data capture, monitoring customer behavior through Pilot Program feedback, and measuring market response to determine future steps to take.

The Pilot Program is proposed as a three-year program with a suite of rebate programs under a "make ready" model, rather than Company ownership. 4 TR 1039-1040. All charging stations qualified to participate in the Consumers Energy rebate program will be networked (i.e., able to communicate with a network management system), be demand response capable, include software and network services capable of capturing 15-minute time-aligned interval data, and support open charging standards and protocols. 4 TR 1040. An EV charging station that is part of the rebate program will be required to communicate with Company systems, provide data, and respond to DR signals based upon Company specifications. 4 TR 1040.

As Mr. Delaney explained in his direct testimony, there will be a residential component, a public charging component, a DCFC component, educational component and a technical component of the Pilot Program. 4 TR 1041-1047. The following chart depicts rebate amounts,

purpose of each component, customer requirements for each component, and additional information (See 4 TR 1041-1047):

<u>CHARGING COMPONENT</u>	<u>REBATE AMOUNT & PURPOSE</u>	<u>CUSTOMER REQUIREMENTS</u>	<u>NOTES</u>
RESIDENTIAL	Up to \$500 per vehicle Incentivize EV drivers to charge at home during off-peak hours and use EVs as a DR asset	<ul style="list-style-type: none"> • Offer proof of purchase of a new or pre-owned EV during the dates of the program • Enroll in Nighttime Savers Rate to maximize customer and grid benefits 	<ul style="list-style-type: none"> • No limit (but estimate 3,000 customers participating) • Not all customers will purchase home charging systems as some customers may live in Multi-Dwelling Units (“MDUs”) or may choose to charge at their workplaces.
PUBLIC	Up to \$5,000 per charger Applies to public, workplace, and MDU Incentivize the installation of public Level 2 chargers	<ul style="list-style-type: none"> • Must be an existing Consumers Energy customer • 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 	<ul style="list-style-type: none"> • Limit: 200 total chargers • Limit: 2 chargers allowed per public site • Limit: for workplace and MDUs, the number of chargers will increase on a sliding scale, commensurate with the number of employees or residents
DCFC	Up to \$70,000 per charger Incentivize locations to become site hosts along highway	<ul style="list-style-type: none"> • Install chargers with a minimum capacity of 125 kW. Dual ports on chargers will be required with both 	<ul style="list-style-type: none"> • Limit: 24 rebates • Limit: up to 2 chargers per site host • Each site will

<u>CHARGING COMPONENT</u>	<u>REBATE AMOUNT & PURPOSE</u>	<u>CUSTOMER REQUIREMENTS</u>	<u>NOTES</u>
	corridors	<p>types of common, non-proprietary charging plugs: CHAdEMO and CCS Combo connectors;</p> <ul style="list-style-type: none"> • Site hosts will be required to agree to charger participation in DR 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. 	receive either 2 DCFCs, or 1 DCFC and necessary infrastructure to readily add a second DCFC in the future
EDUCATIONAL	Recruit site hosts for public Level 2 chargers and DCFCs, recruit customer for the residential rebate, educate existing EV drivers on rates and smart charging, and increase education and awareness overall		<ul style="list-style-type: none"> • Creating awareness and increasing knowledge of EVs and the Program through advertising, bill inserts, and physical handouts; • Expanding the capabilities of the Company's website to provide more detailed and customer-focused information; • Engaging municipalities across the state to work with local

<u>CHARGING COMPONENT</u>	<u>REBATE AMOUNT & PURPOSE</u>	<u>CUSTOMER REQUIREMENTS</u>	<u>NOTES</u>
			<p>organizations that focus on business and economic development who have an interest in learning more about EV options;</p> <ul style="list-style-type: none"> • Partnering with community-based organizations that have strong ties to local customer bases to conduct information sharing activities; and • Working with General Motors to improve a customer's experience when purchasing an EV and the associated charging components by simplifying the process and providing access to relevant information.
TECHNICAL	Develop the IT and administration necessary to ensure that the integration of EVs provides a benefit, rather than a burden, to the grid		<ul style="list-style-type: none"> • Residential: IT development will focus on collection of data from chargers, and the collection of data from the vehicle itself. The software and applications

<u>CHARGING COMPONENT</u>	<u>REBATE AMOUNT & PURPOSE</u>	<u>CUSTOMER REQUIREMENTS</u>	<u>NOTES</u>
			<p>development will also aim to allow customers to view a bill showing EV usage separate from the rest of the house, to avoid the need for a second meter</p> <ul style="list-style-type: none"> • Public/workplace and DCFC-focused IT infrastructure will incorporate data from third-party vendors into smart meter data from Company customers. • IT systems also aim to allow for the communication and analysis of DR events • Administration is needed to manage recruitment, site host selection, outreach and education, rebates, and relationship management between the Company and its site hosts, vendors and residential customers

Success of the Pilot Program will be measured and evaluated based on six measures of success. Those include:

- “1. Fully subscribed Program, or rationale for unfulfilled capacity;
- “2. Ability to convert customers to TOU rate;
- “3. Ability to incentivize customers to charge off peak;
- “4. Increased customer awareness of EVs;
- “5. Functional DR capability; and
- “6. Lessons to leverage in future programs (from paragraph above).” 4 TR 1047-1048.

As Mr. Delaney explained, rather than wait until the end of the three years, the Company will dynamically assess and adjust the Pilot Program components based on the insights gained, captured in annual Pilot Program reviews delivered to the MPSC. 4 TR 1048.

3. Costs: Projected Expense And Cost Recovery

As depicted on Exhibit A-75 (MJD-3), estimated costs for the program are \$7.5 million and are broken down as follows:

- “• Residential: \$500 per customer (cost of the rebate) with no limit on rebates but an estimated 3,000 customers participating, for a first year cost of \$0.5 million and a three-year cost of \$1.5 million;
- “• Public/workplace/MDU: \$5,000 per charger (cost of the rebate), for a 1-year cost of \$0.5 million and a three-year cost of \$1 million (capped at 200 rebates);
- “• DCFC: \$70,000 per charger (cost of the rebate), for a 1-year cost of \$1.4 million and a three-year cost of \$1.7 million (capped at 24 rebates);
- “• Education and outreach: a 1-year cost of \$0.5 million and a three-year cost of \$1.0 million for resources to recruit customers and site hosts for the Program, as well as reach existing EV drivers and educate all customers on EVs; and
- “• Technical development: a 1 year cost of \$1.0 million and a three-year cost of \$2.3 million for the development of the critical IT system underpinning EV network and allowance for two Full-Time Employees (‘FTE’).” 4 TR 1049.

Exhibit A-76 (MJD-4) summarizes how the Company determined the Pilot Program rebate levels and estimated costs for the education and technical development components. See also 4 TR 1050-1051. According to Mr. Delaney, the Company calculates a net benefit to the grid of approximately \$1,900 to \$2,300 per EV in the Company's electric service territory. 4 TR 1052; see also Exhibit A-74 (MJD-2). As Mr. Delaney explained, "[a]fter the first year of the Program, Consumers Energy will re-evaluate the rebates and participation metrics to determine if any changes are needed." 4 TR 1050.

In his direct testimony, Mr. Delaney indicates that the Company requests regulatory asset treatment of the Pilot Program costs. 4 TR 1053. Thus, the proposed Pilot Program, if approved, would result in a deferred asset until the EV Program rebate and related O&M costs are confirmed. 4 TR 1053. If this proposal is approved by the Commission, "the Company requests approval to recognize a regulatory asset to record these deferred amounts." 4 TR 1053. Company witness Harry explained the proposed regulatory asset treatment as follows:

"If the Commission approved regulatory asset accounting for these expenditures, the Company would amortize each annual deferred amount over 10 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. See Exhibit A-75 (MJD-3), page 1, for a computation of the projected EV Program costs. . . . 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. . . . 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 cost over 10 years beginning the year after the cost are incurred.; (iii) following a review of incurred costs in this rate case, and future 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. . . . The alternative recovery approach is to include projected test year program costs in rates for recover.” 5 TR 2126-2127.

As Mr. Delaney explained, the regulatory asset approach allows the Company to invest in EV charging infrastructure now to benefit Consumers Energy’s customers and recover those costs at a later date. 4 TR 1054. Further, the regulatory asset approach allows for a prudency review prior to collection through rates, and spreads the recovery of Program costs and the cost of capital over the life of the EV charger assets, which smooths out the impacts on customers and aligns well with the expected lifetime benefits of the EV Program. 4 TR 1054. Finally, 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 access manageable load in Michigan without owning and operating charging infrastructure. 4 TR 1054. This “provides an incentive for charging site owners to promote EV infrastructure and alleviates range anxiety for customers by accelerating charger availability and promoting awareness while keeping rates lower and expediting the benefits of EV adoption.” 4 TR 1054.

4. Response To Staff And Intervenors Regarding Pilot Program And Costs

a. Response To Staff, MEC/NRDC/SC/EC/MEIBC

Staff and intervenor testimony presented a number of suggestions, which were addressed in Mr. Delaney’s rebuttal testimony. A number of those suggestions either complemented or were conducive to the Pilot Program. Those include the following recommendations:

Staff witness Robert G. Ozar:

- Recommended that the \$7.5 million expenditure cap be limited to rebates for EV supply infrastructure and smart/connected charging stations, technical development, IT, and other pilot related O&M. He then suggested that the Commission set a separate spending cap on ‘make-ready’ capital expenditures associated with service connections at \$2.5 million for a total PowerMIDrive pilot cap of \$10 million.

- Recommended that utility investment in new or modified service connections associated with ‘make-ready’ charging infrastructure be excluded from the rebate program as they would be provided at no cost to site hosts participating in the pilot. This will require suspension of contributions in-aid-of-construction at publicly available EV charging sites included in the pilot, and recovery would be pursuant to standard regulatory practice.
- Recommended that the Company address the upgradability or “future-proofing” of its investment in its upcoming stakeholder meeting prior to committing capital to DCFC site hosts.
- Recommended that the Company file, in Case No. U-20162, and initial rebate schedule for all pilot segments immediately prior to pilot implementation and file revisions as necessary over the course of the pilot.
- Recommended that the Company file an annual report detailing the progress and development of the pilot in this case and, subsequent to each filing, engage in a technical conference.

Staff witness Charles E. Putnam:

- Proposed that costs be amortized over five years instead of 10 years in alignment with the December 11, 2015 Commission Order in DTE Energy Company’s Case No. U-17767.

MEC/NRDC/SC/EC/MEIBC witness Jester and MEC/NRDC/SC/EC witness Max Baumhefner:

- Recommended that the Company closely monitor the uptake of rebates in MDUs and to permit the Company to modify this aspect of the program in its mid-term review if performance is low.
- Recommended that the Company require site hosts to report prices for charging and should report those prices to the Commission and stakeholders at least annually, along with corresponding data for charging utilization and load-profiles by segment.

As discussed by Mr. Delaney in his rebuttal testimony, the Company agrees to implement all of these recommendations. 4 TR 1060-1062, 4 TR 1063, 4 TR 1080.

b. Response To MEC/NRDC/SC/EC/MEIBC And ChargePoint

Additional suggestions and recommendations were made to the Pilot Program that, while worth considering, are not complementary or conducive to the Pilot Program at this time and should not be accepted by the Commission. For example, MEC/NRDC/SC/EC/MEIBC witness Jester suggested that the Commission: (i) encourage the Company to affirmatively communicate with owners of MDUs to recruit participants; (ii) encourage the Company to develop an appropriate program for low-income communities; (iii) encourage the Company to propose a tariff for non-residential Level 2 charging; (iv) remove the cap from the number of DCFCs to be supported and the total spending on this component of the program; and (v) authorize the Company to include a limited pilot of up to six DCFC sites for non-highway functions such as MDUs, certain destinations or low income. As Mr. Delaney explained in his rebuttal testimony, most of these suggestions were not made part of the Pilot Program and are better considered after the Pilot Program has been instituted and information gained that will either support or not support the suggested modifications to the Pilot Program. As Mr. Delaney indicated, once the Company has gained data and further learnings from the pilot, the Company is open to further development of the Pilot Program, but for now it is too early to commit to these suggestions. See 4 TR 1063-1065.

By way of additional example, MEC/NRDC/SC/EC witness Baumhefner recommends that the Company consider increasing the on-peak to off-peak price ratios of its proposed Nighttime Savers rate by lowering the off-peak and super off-peak prices, and further recommended the Commission consider aligning shareholder rewards with more specific metrics, other than spend, and cites to San Diego Gas & Electric's ("SDG&E") Residential Charging Program to support these recommendations. As Mr. Delaney explained in rebuttal, the

SDG&E Residential Charging Program (\$137 million) was substantially larger than the Company's Pilot Program (\$7.5 million) and the Company's Pilot Program focuses on developing learnings. 4 TR 1081. It would, therefore, be premature to add performance metrics at this stage and this recommendation should be rejected. 4 TR 1081. Further, Company witness Collins explained that the Company has proposed the differentials between the on-peak, off-peak, and super off-peak rates based on the locational marginal price ("LMP") forecast for the corresponding time periods, using the methodology that has been accepted by the Commission as used to establish these differentials in past rate cases. While the Company agreed, on rebuttal, that a larger differential between the off-peak and super off-peak rates would further incent customers to use during off-peak hours and, thereby, increased the differential to lower the super off-peak rate for both the Nighttime Savers rate and REV rate (see 5 TR 1590; Exhibits A-143 (LMC-7) through A-145 (LMC-9)), any further adjustment prior to gaining learnings through the Pilot Program is similarly premature at this time. Thus, this recommendation too should be rejected. Finally, Mr. Baumhefner recommended that the Company aim to deploy at least a third of "Public" charging stations in the PowerMIDrive Pilot Program at MDU locations. As Mr. Delaney stated in rebuttal, while "[t]he Company acknowledges MDUs are an important infrastructure component . . . allocating a third [of "Public charging stations in the Pilot Program] to MDUs would limit our ability to effectively deploy publicly-accessible infrastructure across our service territory." 4 TR 1080.

Overall, the Company developed its Pilot Program based on what made sense from the utility perspective and based on the impact on ratepayers. The recommendations by the intervenors, however, are not well-developed enough at this time to establish the overall benefit of incorporating those recommendations at this early stage of the Pilot Program. As discussed in

Mr. Delaney's rebuttal testimony on a number of occasions, the Company, based on learnings from the Pilot Program, will likely seek to modify and expand the elements of the program in the future. Thus, with information gleaned from the Pilot Program, should these recommendations be further developed and be conducive with growth of the Pilot Program, they certainly will be given consideration in the future. However, at this time, the recommendations are premature and should not be incorporated into the Pilot Program.

There were additional recommendations made by intervenors in this case that also should not be accepted by the Commission. These were suggestions and recommendations not incorporated into the Company's Pilot Program, did not complement the proposed Pilot Program, and/or were items that were a little premature, but of possible interest in the future (depending on information gleaned from the Pilot Program). As a result, the Company, consistent with the rebuttal testimony of Mr. Delaney, is not in agreement with those suggestions, that they should not be incorporated into the Pilot Program. 4 TR 1063-1067.

c. Response To The Attorney General And ELPC

In their direct testimony, Attorney General witness Mr. Coppola, and ELPC witness Karl R. Rabago, take issue with the approval of the Company's proposed Pilot Program and regulatory asset treatment, respectively.

First, Mr. Coppola advocates for the wholesale rejection of the Company's Pilot Program and questions the objective of the Pilot Program, the objective of the rebates, the forecasted growth of EVs, the alleviation of range anxiety, the cost/benefit analysis prepared by the Company, the justification for the education and outreach components of the Pilot Program, and the timing of the proposed Pilot Program. These criticisms and recommendations are without merit and should be rejected by the Commission. Instead, the Commission should approve the

Pilot Program as properly supported by Mr. Delaney and as further approved by Staff, ChargePoint, and MEC/NRDC/SC/EC/MEIBC. 4 TR 1067-1073.

Second, Mr. Rabago advocates for the denial of the regulatory asset treatment of EV rebates proposed by the Company in this case. This should also be rejected by the Commission. As Mr. Delaney discussed in his rebuttal testimony, not only is “regulatory asset treatment of program costs a reasonable approach to partially offset the disincentive for a utility to develop an innovative program that is expected to reduce future capital expenditures,” but all of the intervenors, except the Attorney General (who did not address the issue), provided statements of support for the Company’s proposed regulatory treatment, to wit:

- “1. Staff witness Ozar states that: ‘As the design of the pilot has a significant level of detail yet to be established, and actual expenditures will be highly dependent upon customer participation rates, it is reasonable that recovery of program costs be deferred via regulatory asset accounting...’ (page 6, lines 5 through 7);
- “2. Chargepoint witness Ellis notes: ‘Rebates for EV charging hardware, services, and installation, when recovered as a regulatory asset, would be the best model to encourage customer investment in competitive charging technologies and expand these needed technologies throughout Michigan. This approach to cost recovery has a track record of success in demand side management incentive programs. Given the widespread grid benefits that can be enabled through transportation electrification, it would be appropriate and in the public interest for the Commission to approve regulatory asset accounting, recover identified program costs through rates, and, pending future review, permit the utility to earn a return at the authorized rate of return.’ (page 21, line 21 through page 22, line 1);
- “3. MEC/NRDC/SC/EC/EIBC witness Jester recommends: ‘...that the Commission indicate to the Company that it is willing for the current programs to be continued from the current proposed 3-year program until the completion of another rate case, subject to normal prudence standards. The proposed Regulatory Asset accounting for this program should facilitate this.’ (page 70, lines 9 through 13); and

“4. MEC/NRDC/SC/EC witness Baumhefner notes that: “Approving this regulatory asset approach would ensure the Company will continue to consider non ownership models going forward.’ (page 16, lines 12 through 14).” 4 TR 1073-1074.

Mr. Delaney further discusses Mr. Rabago’s remaining and associated criticisms, discusses the basis for his disagreement, and, ultimately, supports the Company’s proposal. See 4 TR 1073-1079. Importantly, as Mr. Delaney explained in rebuttal:

“Mr. Rabago’s recommendation, if adopted, would actually punish the utility and its shareholders for proactively proposing an innovative pilot aimed at reducing customer costs and improving the EV driver experience. The Company’s shareholders would have been better off if the Company had simply made reactive system upgrades as increased EV demand created the need for increased utility capital investment.” 4 TR 1077.

The PowerMIDrive Pilot Program was not designed to build utility load or for the utility shareholders to directly benefit from increased load due to EVs. 4 TR 1077. This Pilot Program is an innovative program that is encouraging customers to use off-peak electricity and reduce the Company’s investment in the system that would have otherwise been needed if charging was performed on-peak, and the regulatory asset approach is an integral part of the Pilot Program. A traditional utility ratemaking approach, as promoted by Mr. Rabago, would create the need to increase capital investments to realize earnings from the increased revenues due to EVs. 4 TR 1077. This increased capital investment would run counter to the overall design of the PowerMIDrive Pilot Program and would result in increased customer costs. 4 TR 1078. Based on this, the Company did not develop a pilot that utilizes a traditional ratemaking approach. In fact, should the regulatory asset approach be rejected, because it is a foundational part of the Pilot Program, the entire program would have to be re-evaluated. Based on the foregoing, the Commission should reject the recommendations of Mr. Rabago.

F. Advance Metering Infrastructure Business Case Update

Consumers Energy began installation of its Advance Metering Infrastructure (“AMI”) smart meters and development of the related AMI systems in August 2012 and completed its investment in the program in the last quarter of 2017. 4 TR 974. During the implementation of AMI, investments and program development responsibilities resided with the Company’s Smart Energy Program team; however, as the various phases of the overall program became finalized, the Company transitioned principal responsibility from the program implementation team to the appropriate operational organizations within the Company. 4 TR 954. As of 2018, all ongoing operational, financial budgeting, and cost management functions associated with the AMI program investment have been transitioned to other operational groups. 4 TR 954-955. Portions of the system now fall under the operational and financial responsibility of the Company’s Customer Experience & Operations Department, IT Department, and the Electric Distribution Operations and Gas Distribution Operations Departments, as appropriate. 4 TR 954-955.

As support for this significant investment, the Commission required Consumers Energy to include updates to its AMI business case in each of the Company’s electric rate case filings throughout the implementation phase of the program. Consumers Energy filed updated business cases in Case Nos. U-17087, U-17735, U-17990, and U-18322 supporting the ongoing investment included in those cases. 4 TR 973. In its March 29, 2018 Order in Case No. U-18322, the Commission instructed the Company to continue filing updates to its AMI business case in future rate cases based on the Commission’s observation that “merely completing the installation of meters and system enhancements does not conclude the implementation phase.” MPSC Case No. U-18322, March 29, 2018 Order, page 80.

Consistent with that directive, Exhibit A-116 (LDW-3) provides Consumers Energy’s AMI business case and sets forth both the costs and benefits for both electric only and

combination electric and gas customers for the 2007 to 2032 time period. 4 TR 973. The business case provides an NPV of the net benefits the AMI Program provides customers. 4 TR 974. The current AMI Program cost/benefit analysis shows savings to customers of approximately \$93.9 million (or a reduction of \$93.9 million in the NPV of revenue requirements). 4 TR 974; Exhibit A-116 (LDW-3), page 5. The present value of electric customer net savings in revenue requirements is \$91.9 million. 4 TR 974; Exhibit A-116 (LDW-3), page 6. The NPV cost-benefit analysis set forth in Exhibit A-116 (LDW-3) demonstrates that the projected rate impact of the entire AMI Program will be a lower cost of service for customers than if the AMI Program were not implemented. The analysis set forth in Exhibit A-116 (LDW-3) demonstrates the continued reasonableness of the investments that were made in the AMI Program.

As noted above, all of the functions of the Company's AMI implementation team have now been transitioned to the various operational organizations in the Company who will manage those aspects of the system in the ordinary course of their business going forward. Hence, the AMI Program has not merely completed installation and development, but has truly completed its implementation phase. Consumers Energy requests that the Commission find that the update provided in this case concludes the Company's obligation to continue supporting business case updates related to investments in AMI. 4 TR 974. Future updates to the business case should not be necessary because any additional costs incurred by the operating organizations going forward will be subject to Commission review in the same manner as any other investment.

Attorney General witness Coppola submitted testimony recommending that the Commission reject the request to discontinue further AMI business cases. 6 TR 2814-2815. He argues that the business case filing requirement should continue until the cumulative benefits of

the program have exceeded the cumulative revenue requirement of the program. 6 TR 2815.

However, Company witness Lincoln D. Warriner explains:

“It is only natural and logical that the timing of benefit values lag investments in technology and business process changes that generate those benefits. The operational changes detailed in my direct testimony generate customer benefits over a long range time horizon. Given that operational improvements enabled by AMI have already been implemented, there is no real benefit to customers in continuing to update the AMI cost/benefit analysis.” 4 TR 991.

In fact, Mr. Coppola himself notes that the cumulative benefits shown in the Company’s business case filing will not exceed cumulative revenue requirement until the year 2028, if all of the forecasts and assumptions included in the business case hold steady. 6 TR 2815. Mr. Coppola’s proposal would mean that the Company would be required to continue filing business cases on this fully implemented program for a decade after implementation was completed.

Mr. Warriner explains that, as time passes beyond the implementation of the program, updated business cases will become less meaningful. Mr. Warriner testified:

“My direct testimony identifies numerous business processes that have fundamentally changed as a result of the implementation of AMI. The Company has transitioned away from historical manual business processes such as reading meters and disconnecting/reconnecting electric service. Residential demand response programs and web-portal displays of daily and hourly electric use have been enabled and implemented. The baseline operational conditions used to estimate the value of business case benefits existed prior to 2012, and have been steadily improved upon with the deployment of advanced meters and implementation of business processes enhanced by the development of the various systems described in my direct testimony. Continuing to estimate benefit values against those historical manual operational processes will lose significance and usefulness in the Company’s future rate cases.” 4 TR 992.

As a result, Mr. Warriner concludes that it would be reasonable for the Commission to relieve the Company of the requirement to file additional updated business cases for the AMI Program

in future rate cases. 4 TR 993. Each of the business cases presented by the Company over several years, including the business case submitted in this proceeding, have shown significant benefits of the AMI Program to customers in terms of the program's impact on revenue requirements. Mr. Warriner testified that there are potential additional benefits that may yet be realized as well, which would be expected to further improve the business case. 4 TR 991-992. The Commission should accept the Company's business case in this proceeding, reject Mr. Coppola's recommendation to continue updates in the future, and render an Order relieving the Company of any further requirement to update the business case for this fully implemented and transitioned program.

G. Interconnection Rules And Process

MEIBC witness Laura Sherman, offers several unfounded criticisms of the Company's interconnection processes. Ms. Sherman presents no evidence that the Company's practices are unlawful under existing, generally applicable interconnection standards established by the MPSC, or that the rates associated with the Company's interconnection procedures are unjust or unreasonable. Indeed, as Ms. Sherman largely acknowledges, the Company's procedures are compliant with the existing MPSC interconnection rules. Those existing rules cannot be changed in an electric rate case, and, as a result, Ms. Sherman's suggestion that the Commission should update those rules is of no moment here. The bulk of Ms. Sherman's testimony is simply irrelevant to this proceeding.

Ms. Sherman openly acknowledges that "[a]ccording to Consumers['] approved rate book, the utility follows the administrative rules established by the Commission (R 460.601a –

R 460.656).”²⁶ 7 TR 3062. When asked whether the Company is “in compliance with Michigan’s current administrative rules regarding interconnection,” Ms. Sherman answers in the affirmative, testifying that “[a]s far as I know they are, in large part.” 7 TR 3075. Although Ms. Sherman’s testimony implies that the Company may to some degree not be in compliance with the Commission’s current interconnection rules, the only evidence of supposed “non-compliance” Ms. Sherman identifies is the fact that the Commission itself has not approved “uniform interconnection procedures, agreements, and application forms . . . for projects larger in size than 150 kW.” *Id.* The Company cannot be faulted, however, simply because the Commission has not approved standard procedures for larger projects to supplement its existing rules. And the fact that the Commission has not approved such standard procedures does not mean that the Company’s procedures for projects larger than 150 kW are out of compliance with the Commission’s rules. Nor does it mean that any electric rates associated with the Company’s interconnection practices are unjust or unreasonable.

To the extent Ms. Sherman makes specific criticisms of the Company’s interconnection procedures, those criticisms are unfairly aimed at procedures that are plainly in accordance with, or even expressly required by, the Commission’s existing interconnection rules. For example, after observing that “[p]otential interconnection customers are given the opportunity to engage with Consumers Energy for up to two hours of consultation prior to submitting an interconnection application,” Ms. Sherman posits that “this amount of time may not be sufficient for a customer proposing a large interconnection project.” 7 TR 3062. Yet “up to 2 hours of technical consultation at no additional cost to the applicant,” regardless of project size, is exactly

²⁶ The MPSC adopted its Electric Interconnection and Net Metering Standards in the May 26, 2009 Order in Case No. U-15787.

what the Commission's interconnection rules direct the Company to provide. Mich. Admin. Code R 460.620(1).

On one hand, having criticized the required two-hour consultation as too quick – Ms. Sherman on the other hand criticizes the Company for “not hav[ing] a pre-application process wherein a potential interconnection customer could quickly check the likely viability of a project at a given point of interconnection at a low cost.” See 7 TR 3062-63; see also 7 TR 3069-70, 3072-3073 (proposing that Consumers Energy adopt “pre-application” and “technical screening” processes). That criticism is off-base. The Commission's interconnection rules expressly state that an applicant may request a two-hour consultation before submitting an application. Mich. Admin. Code R 460.620(1). Again, this provision is not limited to projects of any particular size. *Id.* As explained by Company witness Theresa K. Martinez in her rebuttal testimony, “applicants typically find the consultation results helpful for identifying project viability concerns at an early stage.” 5 TR 2157. Thus the Company does have a pre-application project review process that interconnection applicants use on a regular basis, just as required and intended by the Commission's existing interconnection rules.

Ms. Sherman fails to identify a single example of actual harm experienced by any specific interconnection customer as a result of the Company's current practices. That may be, in part, due to Ms. Sherman's misinterpretation of the Commission's rules. For example, Ms. Sherman claims that Consumers Energy is required to provide all interconnection applicants with the results of an engineering review within 15 business days, and she faults the Company for failing to comply consistently with that standard. See 7 TR 3063. However, the Commission's interconnection rules require a 15-day engineering review period only for Category 3 applicants. Mich. Admin. Code R. 460.620(6)(b); see also 5 TR 2158. For Category

4 and 5 applicants, respectively, the Company has 25 or 45 days in which to provide the results of its engineering review. *Id.* at 460.620(6)(c)-(d). As Ms. Martinez testified in her rebuttal, “it is misleading for Ms. Sherman to compare the review timeline for Category 4 and 5 projects to the review timeline for Category 3 projects, since different MPSC standards and Company procedures apply to different project categories.” See 5 TR 2159.

Ms. Sherman also appears to confuse the standard by first citing the engineering review timeline for Category 3 projects, but then complaining that “for a number of Category 4 and 5 projects submitted over the last 18 months, engineering review and distribution study has taken more than four months to complete after an application is deemed complete.” 7 TR 3063 (emphasis added). Ms. Sherman’s combining of the engineering review and distribution study processes is misleading because the two processes are distinct steps under the Commission’s interconnection rules. See Mich. Admin. Code R. 460.620(5)-(10). Each has its own prescribed timeline. *Id.* at 460.620(6), (8). In the case of a Category 5 project, for example, Consumers Energy has 45 working days to complete an engineering review, and another 60 working days to complete a distribution study. *Id.* at 460.620(6)(d), (8)(d). After accounting for the rule’s specification of working days rather than calendar days, as well as various interim steps – e.g., the applicant’s review and acceptance of estimated distribution study costs, see *id.* at 460.620(7) – the Commission’s existing interconnection rules clearly allow for the possibility that all steps may not be complete for several months. Thus even a timeline of “more than four months,” without additional information as to a particular applicant and application, is not necessarily in violation of the Commission’s rules. See 7 TR 3063. Even if Ms. Sherman had identified a specific example of delay beyond the timelines contemplated in the Commission’s rules, moreover, such a delay would not in and of itself require the Company to change its

interconnection procedures, since those procedures are already designed to comply – and in practice consistently do comply – with the Commission’s rules. It is worth noting, finally, that Ms. Sherman’s testimony does not state that the Company’s interconnection review timelines have harmed any particular customer in any particular way.

Similarly, in criticizing the Company’s interconnection application and payment procedures, Ms. Sherman offers no evidence of an actual problem. See 7 TR 3065-66. Ms.. Sherman asserts that certain unnamed “companies face a number of additional challenges” associated with the Company’s interconnection procedures, including “delays due to errors and lost paperwork.” *Id.* at 3065. Yet while Ms. Sherman states that “unnecessary delays” can occur “[w]hen utilities require paper interconnection applications,” she simultaneously acknowledges that “[i]t is helpful that Consumers [] allows the submission of interconnection applications via email.” *Id.* Not only is Ms. Sherman’s testimony on this point internally inconsistent, but the EQ Research study she cites is largely irrelevant to the Company. See *id.* at 3065-66 and n.1. The EQ Research study says nothing about the Company or even about Michigan in general, and it is focused on the use of paper interconnection applications – something that the Company does not require. While it is true that the Company does not have an electronic payment system for fees associated with interconnection applications, Company witness Martinez observed in her rebuttal testimony that “the majority of checks sent by mail to pay for fees” associated with interconnection requests are actually received before the corresponding interconnection applications themselves. See 5 TR 2160. Ms. Martinez is not aware that mailed payments have caused a problem for any of the Company’s actual interconnection customers. *Id.* at 2161. Ms.. Sherman offers no evidence to suggest otherwise.

In a number of instances, it appears Ms. Sherman would prefer that the Company's interconnection procedures comply with the standards required in other states, see, e.g., 7 TR 3069 and n.2, 3072-3073 and nn. 4-8, or for projects under the jurisdiction of the FERC, *id.* at 3069-3070. Such criticisms are not properly directed at Consumers, however, because the Company's obligation is to comply with the interconnection standards previously established by the MPSC and generally applicable in the state of Michigan. As Ms. Martinez testified, Consumers does comply with those standards, and the existing MPSC interconnection rules do not authorize Consumers to implement and recover the costs of the various additional procedures proposed by Ms. Sherman. 5 TR 2162. It is therefore irrelevant to this case whether regulators and legislators in other jurisdictions may employ interconnection standards that Ms. Sherman believes to be preferable to the MPSC's standards.

Ms. Sherman's argument is ultimately with the Commission rather than with the Company's. A significant portion of Ms. Sherman's testimony is, in fact, expressly directed to the MPSC. See 7 TR 3075-3083. But, this is not the correct venue for prodding the Commission to change its existing interconnection rules. At issue, here are the Company's rates, and there is no mechanism by which an order of the Commission in this proceeding could change the interconnection standards that are applicable to all utilities and interconnection customers in the state of Michigan – nearly all of whom are not parties to this case. To be sure, as Ms. Sherman is aware, Staff has already initiated a broader stakeholder process designed to address potential changes to the MPSC interconnection rules. See 5 TR 2156, 7 TR 3076. Ms. Sherman's criticisms would more appropriately be raised by MEIBC in that stakeholder process and ultimately before the Commission in a rulemaking proceeding. Consumers Energy "will likely

participate in that process” as well, according to Ms. Martinez, and the Company will “fairly evaluate changes proposed by Staff or other stakeholders.” 5 TR 2164.

In sum, Ms. Sherman’s testimony should be afforded no weight in this case. Ms. Sherman all but concedes that the Company’s interconnection procedures are in compliance with the Commission’s existing administrative rules, and she offers no evidence that the Company’s compliance with existing MPSC standards has harmed any actual customer in any concrete way, or that the rates associated with the Company’s interconnection procedures are unjust or unreasonable. Ms. Sherman wishes to see the Commission change its existing interconnection rules. Whatever the merits of that objective, however, it cannot be accomplished here.

H. Requested Accounting Approvals

1. Traverse City Service Center Acquisition Costs Accounting

Company witness Harry provided testimony supporting the Company’s request for recovery of Traverse City Service Center (“TCSC”) costs, which have been recorded in Consumers Energy’s general ledger Account 114, *Electric Plant Acquisition Adjustment*. 5 TR 2121. Mr. Harry explained that the Company has utilized the TCSC pursuant to an operating lease since 1955. 5 TR 2122. In 2017, the Company purchased the TCSC from the lessor for \$1.9 million. 5 TR 2121. Under these circumstances, FERC Docket No. AC17-163-000 requires the Company to record an acquisition cost adjustment for the TCSC based on the lessor’s original cost for the plant and estimated accumulated depreciation. 5 TR 2121, 2123. In order to extinguish the amount recorded in Account 114, the Company needs Commission approval to amortize the TCSC acquisition adjustment and record the amortization expense in Account 406, *Amortization of Electric Plant Acquisition Adjustment*. 5 TR 2121. The Company proposed a 15-year amortization period, which represents the remaining book life of the TCSC.

5 TR 2123. If approved for a 15-year amortization, the resulting amortization expense is \$126,129 annually. 5 TR 2123.

Staff witness Putnam supported the Company's proposal, indicating that it is "sound accounting treatment" and the same as proposed for the Company's Saginaw Service Center Acquisition costs in MPSC Case No. U-17735. 6 TR 2553. No party opposed the Company's request. Therefore, the Company requests that the Commission approve the accounting treatment for the TCSC set forth in Mr. Harry's testimony.

2. Regulatory Accounting For Investments In Cloud-Based Technologies

Company witness Harry also provided testimony supporting the Company's request for deferred regulatory accounting treatment for "cloud-based" IT solutions. 5 TR 2123-2126.

Mr. Harry explained the reason for the Company's request as follows:

"The cost for traditional IT systems hosted on-premises qualify for capital accounting treatment. Under recently issued GAAP (FASB Accounting Standard Update 2015-05), the costs associated with cloud-based solutions generally do not qualify for treatment as a capital asset and are expensed as O&M. The disparity in accounting treatments between these two software approaches creates a regulatory incentive for utilities to invest in on-premises software solutions, and creates financial hurdles that hinder utilities from realizing the benefits of cloud-based technologies. The value of cloud-based solutions has been recognized by the National Association of Regulatory Utility Commissioners ('NARUC'). At its 2016 annual meeting, NARUC adopted a formal resolution: 'Encouraging State Utility Commissioners to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements.' This accounting request is directly aligned with the NARUC resolution." 5 TR 2125.

If deferred accounting for cloud-based IT solutions is approved, the accounting treatment would follow the accounting treatment for traditional IT investments, and the impact on customer rates would be spread over the future economic life of the cloud-based investments. 5 TR 2124.

Mr. Harry testified that the Company is requesting the accounting authority to accumulate IT project implementation costs for cloud-based solutions in Plant Account 303, *Miscellaneous Intangible Plant*. 5 TR 2123. Additionally, Consumers Energy is requesting the authority to amortize the intangible asset to expense over the expected useful life of the cloud-based solution. 5 TR 2123-2124. Staff witness Putnam provided testimony supporting the Company's proposed accounting treatment for cloud-based IT solutions. No party opposed the Company's request. Therefore, the Company requests that the Commission approve the deferred accounting treatment for cloud-based IT solutions set forth in Mr. Harry's testimony.

VII. REVENUE DEFICIENCY CALCULATION

For the reasons discussed in this Initial Brief, and as set forth in the evidence presented by Consumers Energy, Consumers Energy requests the Commission find that, without rate relief, Consumers Energy will experience a revenue deficiency for the test year ending December 31, 2019 of \$43,914,000. The calculation of this deficiency is summarized in Appendix A.

VIII. COST OF SERVICE, RATE DESIGN, AND TARIFF ISSUES

A. COSS

1. Company's Position

Company witness Aponte, Principal Rate Analyst-Lead in the Rate Analysis and Administration section of the Rates and Regulation Department, presented the Company's COSS by rate class. 5 TR 1648-1670. Ms. Aponte described the nature of a COSS:

“A COSS by rate class is a systematic functionalization, classification, and allocation of a utility's fixed and variable costs to serve. Each COSS I have 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." 5 TR 1648-1649.

Ms. Aponte presented two test year COSSs in the Company's initial filing in this case. The Test Year Electric COSS – Version 1 ("COSS Version 1") is in Exhibit A-16 (JCA-1), Schedule F-1. The allocation methodologies used in the COSS Version 1 conform to the Commission's COSS decisions in Case No. U-18322. 5 TR 1653. COSS Version 1 was not used for rate design purposes in this case, but provides a base for comparison purposes with the version of the COSS the Company is proposing. 5 TR 1654. The Test Year Electric COSS – Version 2 ("COSS Version 2") is in Exhibit A-16 (JCA-2), Schedule F-1.1. The COSS Version 2 differs from the COSS Version 1 in five respects: (i) it proposes a change in the production capacity allocator; (ii) it proposes a change to the number of historic years used for the development of the average test year profile; (iii) it uses a single residential customer load profile, (iv) as required by the Commission in Case No. U-18322, it restates 4 Coincident Peak ("CP") and 12 CP demand allocators considering demand line loss factors, and (v) it updates the average meter equipment costs as a result of the full deployment of smart meters. 5 TR 1654, 1669-1670. The Company originally proposed that the Commission approve COSS Version 2 in this proceeding. As will be discussed below, the Company in rebuttal proposed certain changes to its proposed COSS in response to positions taken by Staff and Intervenors.

The Company proposed in COSS Version 2 to change the production capacity allocator from the approved 4 CP 75/0/25 methodology to the Average and Excess ("A&E") cost allocation methodology. 5 TR 1655. Ms. Aponte explained that the A&E methodology develops the weighted average of two components: (i) the average component (or "average demand"), which represents each rate class's average hourly energy consumption throughout the test year, and is calculated by dividing annual energy consumption for each rate class by the

8,760 hours in a year; and (ii) the excess component (or “excess demand”), which represents each rate class’s average contribution to the overall system peak demand during the designated peak months (i.e., 4 CP). 5 TR 1655-1656. The average demand is an energy allocator that apportions the capacity required if all customers used energy at a constant 100% load factor. The excess demand is the proportion of the difference between the sum of all classes’ selected CPs and the system average demand. 5 TR 1656.

While the current 75/0/25 production allocator identifies base load usage and related costs, it fails to consider each class’s load factor. 5 TR 1657. Load factor is the ratio of average demand and maximum demand occurring over a period. Load factor is lower for customers with significant variation between the demand and energy usage, and is higher for customers with less variation between demand and energy usage. 5 TR 1657-1658. Class load factors are important in selecting a production capacity allocator because of the insight they provide into which rate classes are contributing more to peak production plant. Ms. Aponte testified:

“To serve the low load factor peaks, generation units are sitting idle for long periods of time, therefore 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 charged less overall per kWh (average demand), while those with peak demands much higher than their average demand are allocated more peak costs (excess demand). This is the consequence of serving their load during high-peak and even critical-peak times, when costs are higher.”
5 TR 1658.

Because the A&E methodology considers class load factors, it better identifies how efficient customer classes are using energy and represents a more accurate matching of costs to the cost causers. 5 TR 1657. The A&E methodology is recognized by the NARUC and is described in the NARUC Electric Utility Cost Allocation Manual (January 1992) (“NARUC Manual”). 5 TR 1658. In addition, the A&E methodology has been used by several states

throughout the country. 5 TR 1658. The A&E methodology also places more sensitivity on demand contributions and reduces sensitivity on annual energy usage, which is consistent with the Company's efforts to encourage the efficient use of electric service through pricing mechanisms such as TOU rates and the Residential Dynamic Pricing Program. 5 TR 1660.

In its original filing in this case, the Company proposed using five years of historic profiles (2012 through 2016) to develop the average test year load profile as opposed to the three-year average (2014 through 2016) used in COSS Version 1. 5 TR 1661. The Company made this proposal to lessen the weight of those years with extreme weather. 5 TR 1662-1663. Ms. Aponte noted that an improvement of the redesigned load study for 2017 is the significantly increased sample size for residential and secondary commercial customers. 5 TR 1663. In rebuttal, as will be discussed below, the Company responded to criticism of using the five-year average by proposing the use of three years of historic profiles (2015 through 2017) to develop the average test year load profile.

The Company's proposal to combine the Residential Service Secondary Rate RS and Residential Service Time-Of-Day Secondary Rate RT into a single load profile in the COSS is to support the Company's residential rate design proposal. 5 TR 1664. The Company also restated the 4 CP and 12 CP demand allocators in COSS Version 2 by using the monthly demand loss factor in the 2016 Loss Study Report, available at Revised Exhibit A-29 (JRA-14), page 6.

In the Commission's March 29, 2018 Order in Case No. U-18322, page 99, the Commission required the Company to justify its current methodology for allocating distribution system costs in its next rate case. In response, Ms. Aponte explained that the "current allocation of the Company's distribution costs follows the classification of these costs into customer related versus demand related," as defined by the Commission in its orders since the 1970s related to the

customer charge calculation. 5 TR 1666. Consumers Energy does not agree with this classification, and instead believes that the Minimum Distribution System (“MDS”) and the Zero-Intercept methods, both of which determine the portion of distribution costs that are customer related, would better reflect the use of the distribution system by customers. 5 TR 1667-1668. Several utilities across the country also classify a percentage of their distribution system as customer related. 5 TR 1668. Customer-related costs are currently allocated using number of customers and meter costs by class, and demand-related costs are primarily allocated using the non-coincident peaks (“NCPs”) of each customer class. 5 TR 1668-1669.

The Company is not proposing to change the classification of distribution costs in this proceeding to the MDS, Zero-Intercept, or any other methods. The Company is currently gathering the data necessary to perform the calculations and analyses to support potential distribution system classification and allocation proposals in future proceedings. 5 TR 1669. In this case, the Company is proposing to update average meter equipment costs as a result of the full deployment of smart meters. 5 TR 1669-1670.

In rebuttal, Ms. Aponte updated the Company’s COSS to reflect an updated revenue requirement (“COSS Version 3”). 5 TR 1700. Similar to the COSS Version 2, the COSS Version 3: (i) uses the A&E methodology for the production capacity allocator; (ii) uses a single residential customer load profile; (iii) restates 4 CP and 12 CP demand allocators considering demand line loss factors; and (iv) updates meter costs for residential and secondary commercial rate classes. 5 TR 1700. Additional changes incorporated into COSS Version 3, discussed in more detail below, include: (i) using three-year average 2015, 2016, and 2017 to develop the average test year load profile; (ii) updating the street lighting determinants; (iii) excluding land leased to Michigan Electric Transmission Company (“METC”) from the historic baseline; and

(iv) allowing for the excess demand to include negative values in the calculation of the A&E allocator for production costs. 5 TR 1700.

2. Response To Staff

a. Production Allocator

Staff opposed the Company's proposed A&E production allocator. 6 TR 2432. Staff witness Susan E. Goepp argued that the Company's proposal does not use the NCP recommended by NARUC, and thus does not properly account for excess demand. 6 TR 2432. Ms. Aponte explained that the NCP recommendation in the NARUC Manual is not a prescribed formula that all utilities are required to apply. 5 TR 1676. Page 67 of the NARUC Manual makes clear that "no method is prescribed by regulators to be followed exactly," and methodologies "can be revised to reflect new technology, new rate design objectives, new information, or a new analyst with new ideas." For this reason, a number of jurisdictions have adopted 4 CP (rather than NCP) in combination with the A&E methodology. 5 TR 1676-1677. The Company does not agree that the NCP A&E method should be used. The 4 CP A&E method recognizes that the Company sizes its facilities to meet customer demand during the summer peaking months. 5 TR 1677.

Staff witness Goepp recommended the continued use of the existing 4 CP 75/0/25 production allocator because: (i) it is the historically accepted method; (ii) it reflects the combination of both demand and energy; and (iii) different rate classes have different contributions to line losses. 6 TR 2433-2434. These concerns do not prevent the Commission from approving the A&E production allocator. Under MCL 460.11(1), the Commission may modify the 75/0/25 methodology if it determines that it does not ensure that rates are equal to the cost of service. As discussed, the A&E methodology more accurately reflects the cost of service. 5 TR 1677. The A&E methodology also combines demand and energy, with the first portion of

the formula using hourly energy consumption and the second portion of the formula using excess demand, both of which are weighted by the system load factor. 5 TR 1677. While Ms. Goepf stated that increasing system load factor spreads total system costs across a larger number of sales units and reduces the cost burden for individual customers (6 TR 2433), such a result is discouraged by maintaining the energy weighting in the production allocator. 5 TR 1678. In addition, the A&E methodology fully reflects the impact of line losses in both the demand component and all energy allocators. 5 TR 1678.

Staff witness Goepf also performed an analysis to confirm the accuracy of the 25% energy allocation assumption by considering “which of the Company’s production assets were base load in nature.” 6 TR 2436. Ms. Aponte expressed a number of concerns with Staff’s analysis. First, the analysis includes as “base load” 100% of the active Campbell and Karn units, which fails to take into account the current state of the electric market. 5 TR 1679. The coal plants that have historically been considered “base load” are not the resources serving 100% of the minimum system load today. 5 TR 1679. Depending on market conditions, it may be economically beneficial to offer natural gas plants into the MISO rather than ramping up production of a coal plant. 5 TR 1680. Thus, only the minimum load that these coal units produce should have been considered “base load” for the purposes of Staff’s analysis. 5 TR 1679.

Another concern with Staff’s analysis is that it includes 100% of the retired coal plants J.R. Whiting and J.C. Weadock and 100% of the hydro plants Hardy, Hodenpyl, and Tippy as base load. It is not appropriate to include the costs of retired coal units when determining the allocation of projected test year production costs, and it is inappropriate to include the hydro units as “base load” because the units depend on water and cannot guarantee a minimum supply.

5 TR 1680. Staff's analysis also fails to include the cost of the Jackson plant in the years 2015 and 2016. 5 TR 1680.

Staff's analysis also determines the relationship between the minimum hour as a percentage of maximum hour by using the minimum hour data at generation and the maximum hour data at distribution, which would not represent the system peak before line losses. 5 TR 1681. Staff used the load delivered at the distribution level to ultimately calculate a percentage of base load energy of the total average energy for the year, which inappropriately considers load at two different levels of the system (generation and distribution) without the consideration of line losses. 5 TR 1681. Ms. Aponte adjusted Staff's analysis to correct the concerns she identified, which resulted in an energy weighting of 11% (as opposed to the 25% energy weighting supported by Staff). 5 TR 1682.

The use of the 4 CP A&E methodology appropriately makes the customers creating the peaks responsible for the higher costs required to meet the highest demands of the year. 5 TR 1680. Accordingly, the 4 CP A&E methodology is a better reflection of how customers utilize the Company's capacity than the 4 CP 75/0/25 method. If the Commission accepts Staff's analysis and chooses not to adopt the A&E production allocator, then the Commission should revise the current allocator to 89/0/11 (89% on 4 CP demand, 11% on total energy) based on Ms. Aponte's update to Staff's analysis. 5 TR 1682.

b. Average Load Profile

Staff also did not agree with the Company's initial proposal to use five years of historic profiles as the test year load profile. 6 TR 2439. Staff recommended using a three-year average because the system peak is more likely to occur in July, the three-year average most closely approximates the 15-year average, and using three years maintains a consistent approach. 6 TR 2440. As discussed, the Company proposed using a five-year load average in this case

because of concerns with the “data outliers caused by unique weather patterns and the dwindling sample size of the residential and secondary classes.” 5 TR 1683. In rebuttal, Ms. Aponte indicated that the Company had completed the 2017 load study, which included expanded sample sizes for residential and secondary commercial customers. 5 TR 1683. Thus, the Company developed using a three-year load study (2015, 2016, and 2017), which is consistent with the results of the Company’s originally proposed five-year average and with the three-year average methodology that was approved in Case No. U-18322. 5 TR 1683.

The three-year average 2014, 2015, and 2016 proposed by Staff results in a 4 CP test year allocator at the generation level that is less consistent with the three-year average 2013 through 2015, the five-year average 2012 through 2016, and the three-year average 2015 through 2017. 5 TR 1683-1684; Exhibit A-129 (JCA-7). Recognizing Staff’s proposal to maintain a three-year average, the Company proposes the use of the three-year 2015 through 2017 average as a more accurate reflection of load profiles. The use of the 2015 through 2017 average addresses Staff’s concerns because the system peak occurred in July in 2017, the 2015 through 2017 average closely approximates the 15-year average, and the 2015 through 2017 average maintains the three-year average approach. 5 TR 1685.

c. **Energy Intensive Pilot Capacity Costs**

Staff witness Isakson recommended that the Company develop a COSS that includes capacity costs for the Energy Intensive Pilot (“EIP”) customers in the next general rate case. 6 TR 2368. Rate EIP still has fewer than 20 customers, which is not enough customers to develop a meaningful profile. 5 TR 1686. Because Rate EIP customers are subject to market prices during CPP events, the Company has reduced the capacity cost responsibility in the COSS. 5 TR 1686. However, the Company will agree to avoid reducing Rate EIP capacity costs

in the COSS in its next rate case proceeding, but may still need to adjust the allocation in rate design to maintain the economic incentive to participate in Rate EIP. 5 TR 1686.

3. Response To The Attorney General

Attorney General witness Coppola recommended that the Commission reject the Company's proposed A&E production allocator. 6 TR 2877. As discussed above, the A&E production allocator is a better reflection of how customers use the Company's capacity and the Commission should adopt the A&E methodology. 5 TR 1699. Mr. Coppola also contended that it is "premature and unwise" to make any changes to the distribution cost allocation methodology until the Company performs a more complete study. 6 TR 2877. Consumers Energy did not propose any change to the allocation of distribution costs in this case. The Company has proposed to update the average meter equipment costs as a result of full deployment of smart meters in 2017, which update appropriately reflects the status of smart meter deployment. 5 TR 1699-1700.

4. Response To ABATE

a. Loss Factors

ABATE witness Pollock argued that the Company should have used the CP demand loss factors to derive the 4 CP, 12 CP, and class peak demands at the generation level in its COSS Version 1. 7 TR 3472. ABATE's recommendation is not consistent with the purpose of COSS Version 1, which reflects the COSS methodologies approved by the Commission in Case No. U-18322 for comparison purposes. 5 TR 1696. In Case No. U-18322, the Commission required the Company "in its next rate case, to present a line-loss study that considers demand line loss factors restating the 4 CP and 12 CP demand allocators from the meter to the generator." MPSC Case No. U-18322, March 29, 2018 Order, pages 92-93. The Company fulfilled this requirement by restating the 4 CP and 12 CP demand allocators in COSS Version 2 and illustrated the change

in methodology compared to the COSS Version 1 model approved in Case No. U-18322. 5 TR 1696.

b. Production Allocator

ABATE witness Pollock proposed that the proper allocation of the A&E methodology requires the use of the annual load factor to weight the average demand component. 7 TR 3471. Consumers Energy agrees that the annual system load factor should be applied to the average demand in the 4 CP A&E methodology, which is consistent with Ms. Aponte's description of the A&E methodology in her direct testimony in this case. See Exhibit AB-35. Ms. Aponte testified that 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." 5 TR 1656. And when noting the other states that use A&E methodologies, Ms. Aponte pointed out that "five of those us[e] 4 CP as the basis for the excess portion of the allocator." 5 TR 1658. Thus, the Company intended to only apply the 4 CP to the excess demand component of the A&E methodology, not the average demand component. Exhibit AB-35.

5. Response To MEC/NRDC/SC/EC/MEIBC

a. Production Allocator

Similar to Staff, MEC/NRDC/SC/EC/MEIBC witness Jester contended that the Commission should not adopt the proposed A&E methodology, and that the Company should instead maintain the current 75/0/25 method. 6 TR 2628. As discussed in response to Staff's proposal, the A&E methodology considers each class's load factor and results in a more accurate matching of costs to the cost causers than the 75/0/25 method. 5 TR 1687. Mr. Jester criticizes the A&E method by arguing that it "fails to recognize that the type of plant used to serve

continuous demand is more expensive per unit capacity than the type of plant used to serve peak demand.” 6 TR 2624. Ms. Aponte explained that based on market conditions, some units traditionally categorized as “peakers,” such as natural gas plants, are fulfilling part of the base load demand, so that the traditional role of “base load” and “peaker” units is not a helpful distinction when allocating production costs. 5 TR 1687-1688.

Mr. Jester testified that he “prefer[red] a marginal cost method in which the marginal cost of demand at each time is charged to all customers.” 6 TR 2625. However, Mr. Jester’s proposal is not consistent with the traditional embedded cost method that the Commission has historically evaluated and approved, and would require another mechanism to ensure that the Company would recover its revenue requirement. 5 TR 1688. Mr. Jester also argued that the equivalent peaker method is the most accurate embedded cost allocation. 6 TR 2626. However, the NARUC manual indicates that the equivalent peaker method relies “more heavily on system planning data in addition to load research data,” which raises concerns as to the data requirements and complexity involved in this method. 5 TR 1688. For the reasons discussed above, the Commission should adopt the A&E production allocator method.

b. Average Load Profiles

Also similar to Staff, MEC/NRDC/SC/EC/MEIBC witness Jester did not agree with the Company’s proposed five-year average load profile. 6 TR 2629. As discussed, the Company proposed the five-year average load profile in an effort to reflect the most accurate representation of customers’ load shapes in the test year profile. 5 TR 1689; Exhibit A-129 (JCA-7). In response to Staff’s concern with using the five-year average load profile, the Company proposes to instead use the three-year average load profile 2015 through 2017 in this case. 5 TR 1685.

c. Residential Load Profiles

MEC/NRDC/SC/EC/MEIBC witness Jester opposed the Company's use of a single load profile for all residential rate classes. 6 TR 2631. The Company's rate design in this case provides residential customers the opportunity to reduce their costs when they avoid usage during critical time periods. 5 TR 1690. Also, Rate RT, which the Company has proposed to combine with Rate RS, only represents 0.48% of the total residential sales. 5 TR 1690. The Company cannot develop historic load profiles for proposed rates that do not exist today, and does not advise developing profiles for a limited number of customers or for those that have been under a particular rate for a limited time because the data is insufficient to develop a meaningful profile. 5 TR 1690. Combining the Rate RS and RT profiles is reasonable and fair to all residential customers. 5 TR 1689-1690.

Mr. Jester also argued that the Company should have reflected the expected reduction in residential load as a result of the new rate design in the COSS. 6 TR 2637. Mr. Jester's proposed reduction is not necessary and is contrary to the Company's methodology for developing the test year load profile. The Company develops the test year load profile by averaging historic load profiles. These averages over time will reflect any reduction of residential on-peak load. 5 TR 1690.

d. Loss Factors

Mr. Jester expressed concern that the Company did not apply distinct loss factors to convert 4 CP and 12 CP customer class demand to generation demand in COSS Version 1. 6 TR 2362. As discussed in response to ABATE, COSS Version 1 is provided for comparison purposes and reflects the COSS methodologies approved in Case No. U-18322. The 4 CP and 12 CP demand allocators were appropriately restated in COSS Version 2. 5 TR 1690-1691.

Mr. Jester also “urge[d] the Commission to require that the Company’s future Cost of Service Studies include the use of loss adjustment factors specific to each of the energy and demand allocators used in the Cost of Service Study.” 6 TR 2633. The Company does not have the data available to update the COSS in the manner Mr. Jester recommends. 5 TR 1691. Company witness Anderson explained that energy losses for Primary LVD lines are calculated by modeling a sample set of circuits at nine different system gross load levels, which are chosen to represent the entire system gross load range observed over all hours in the study year, and not subsets of hours such as peak hours or summer hours. 5 TR 1990. Also, the Secondary LVD energy loss factor is calculated as the loss remaining after all other system component losses are allocated. Since the total system energy loss percentage is calculated from annual totals, only an annual Secondary LVD energy loss factor can be calculated. 5 TR 1990.

e. **Distribution Costs**

Consumers Energy is not proposing to change the classification or allocation of distribution costs in this case, but continues to gather the data necessary to support future potential distribution system classification or allocation proposals. 5 TR 1669. Although the Company is not recommending a change in this proceeding, Ms. Aponte discussed the Company’s current view that the MDS method would better reflect customers’ use of the distribution system. 5 TR 1667-1668. Mr. Jester argued that the Commission has a consistent history of rejecting the use of the MDS method. 6 TR 2615. While the Commission has rejected the use of the results of the MSD method as the basis to establish the customer charge in rate design, it is not clear that the Commission has rejected the use of the MSD method for the classification of distribution costs. 5 TR 1692. The process of classifying costs within the COSS is distinct from the process of setting customer charges within rate design. 5 TR 1692-1693.

Mr. Jester criticizes the MSD method by arguing that distribution costs identified as customer-related in this method do not change with the addition or removal of a customer to the system, and that most customer additions or removals do not change the geographic reach of the distribution system. 6 TR 2616. Where customer additions do require distribution system extensions, Mr. Jester argued that costs incurred are related to expected energy sales and not the number of customers. 6 TR 2616. Mr. Jester argument is incorrect. Adding a new customer necessitates the installation of a meter, service, and other portions of the distribution system. 5 TR 1693; Exhibit A-52 (AJB-19). The important consideration for the COSS is how the Company's 1.8 million customers contribute to and are responsible for the cost of the system. The distribution system meets peak customer demand and provides system access regardless of peak demand or consumption. 5 TR 1693. A customer with little or no usage or peak demand still requires a minimum portion of the distribution system in addition to the meter and service. 5 TR 1693. That customers contribute to distribution service extensions does not impact whether the costs are customer related, and many system improvement projects are performed for the benefit of all customers where there is not a particular customer contribution to the project. 5 TR 1694.

Mr. Jester recommended that the Commission initiate a separate stakeholder process to examine distribution system costs. 6 TR 2619-2620. An additional stakeholder process is not necessary. The Company is currently collecting data and preparing studies to support a change in the classification and allocation of its distribution costs, and will use this data and the results of engineering studies to propose potential distribution system allocation proposals in future cases. 6 TR 1694-1695.

6. Response To Energy Michigan

Energy Michigan witness Zakem argued that the SRM charge that the Company proposed does not follow the methodology approved in Case No. U-18239, because the MW used in the denominator of the calculation was not taken from the Company's SEC Form 10-K. 7 TR 3146-3148. Company witness Blumenstock agreed to adjust the Company's originally proposed denominator, but disagreed with sourcing the denominator from the Company's SEC Form 10-K. The denominator of the SRM Capacity Charge calculation represents the amount of capacity that is the basis for the fixed costs in the numerator of the SRM Capacity Charge calculation. 5 TR 1457. Rather than using the maximum tested capacity of all Company resources in the SRM calculation (as reflected in the Company's SEC Form 10-K), it is more appropriate to use the amount of ZRCs assigned to the Company's capacity resources by MISO. 5 TR 1457.

ZRCs indicate a resource's available capacity after discounting for the resource's effective forced outage rate, with one ZRC sufficient to serve one MW of demand. 5 TR 1457-1458. ZRCs are the amounts MISO assigns to, and accepts from, the Company's resources to satisfy the Company's capacity obligation. 5 TR 1458. Demand for customers that return to the Company's bundled service and that need to pay the SRM Capacity Charge must be satisfied with ZRCs, not MW. 5 TR 1459. Use of the historical SEC Form 10-K value is also not appropriate in this case because it does not consider the Company's plans for the test year, nor does it express the capacity value of the Company's resources in terms of ZRCs. 5 TR 1458.

The Company proposed that the PSCR information included in Exhibit A-33 (RTB-1) be used as the source of the SRM Capacity Charge denominator, which aligns with the fixed costs in the numerator of the SRM Capacity Charge calculation. 5 TR 1458; Exhibit A-131 (JCA-9),

line 19. Using the PSCR forecast in this case, the revised denominator is 8,336 ZRCs. See Exhibit A-134 (RTB-4). This revised denominator results in an SRM Capacity Charge of \$335.99 MW/Day. Exhibit A-131 (JCA-9).

7. Response To The Cities Of Flint And Grand Rapids

On behalf of the Cities of Flint and Grand Rapids, Mr. Jester reiterates his opposition to the Company's proposed A&E production cost allocation methodology. 6 TR 2743. For the reasons discussed above, the Commission should adopt the Company's proposed A&E methodology. Mr. Jester recommended that if the Commission accepts the use of the A&E methodology, the Commission should require that the COSS include negative values for excess demand. 6 TR 2744. Consumers Energy agrees with this suggestion and permitted negative values for excess demand as applicable for a rate class in COSS Version 3. 5 TR 1695; Exhibit A-130 (JCA-8). Mr. Jester also noted that the Company's initial filing did not incorporate the proposed LED conversions into the streetlighting sales forecast. 6 TR 2740. As discussed above, the Company agreed in rebuttal that the sales forecast should be adjusted to incorporate the proposed LED streetlighting conversions. 5 TR 1763. Ms. Aponte included this change in COSS Version 3 at Exhibit A-130 (JCA-8). 5 TR 1695. As to Mr. Jester's criticism of the current distribution system allocation (see 6 TR 2741), the Company recognizes the opportunity for improvement of the distribution classification and allocation methodologies, and is in the process of studying and developing potential improvements. 5 TR 1695-1696.

8. Response To Hemlock Semiconductor Operations LLC

a. Land Leased To METC

Hemlock Semiconductor Operations LLC ("HSC") witness Amanda M. Alderson testified that the Company indicated during discovery that it had mistakenly included test year costs for assets and associated land leased to METC that was transferred to the FERC

jurisdiction in 2017, and recommended that the Company correct this error. 6 TR 2218. Consumers Energy agrees. The Company removed the historic costs for the land leased to METC in COSS Version 3 at Exhibit A-130 (JCA-8). 5 TR 1697.

b. Overhead Line Expenses Allocation

HSC witness Alderson argued that because Voltage Level 1 customers take service at 120 kV or above, the cost of certain overhead line expenses that operate at 46 kV or below should not be allocated to Voltage Level 1 customers. 6 TR 2218. Ms. Aponte explained that HSC's recommendation to "create three new allocators requires modeling within the COSS for them to properly function without manual adjustments," and the Company was unable to complete the modeling and testing at this time. 5 TR 1697. Consumers Energy may propose future changes to the COSS after additional consideration, and notes that the impact of HSC's requested updates are de minimis. 5 TR 1697; see also 6 TR 2220, Table 1 (comparing columns "Consumers Corrected" and "HSC Corrected").

c. Substation Ownership Credit

Consumers Energy determined a credit for General Service Primary Demand ("GPD") Rate customers who own their own substations, consistent with the methodology approved in Case No. U-18322. 5 TR 1671-1672. The calculation determines the costs per kW that have been allocated to GPD Voltage Level 1 and Voltage Level 2 customers for substations. 5 TR 1672. The Company determined the substation rate base, which was multiplied by the pre-tax ROE, and then added depreciation expense, O&M expense, and other taxes. 5 TR 1672. Revenue credits were also incorporated to arrive at a total revenue requirement, which was divided by the maximum demand in MW to determine the substation ownership credit. 5 TR 1672. The Company's originally filed credit is provided at Exhibit A-31 (JCA-4), and the

revised credit as a result of the COSS updates previously discussed is provided at Exhibit A-132 (JCA-10).

HSC witness Alderson argued that the substation ownership credit is understated, and recommended that the credit “provide for a 76% and 28% credit off of the Distribution Demand Charge approved in this case for Voltage Level 1 and 2 customers, respectively.” 6 TR 2239. Ms. Alderson argued that the substation ownership credit should include an offset for a portion of the costs related to 138 kV lines. 6 TR 2234. Ms. Alderson’s proposed offset generalizes the information that may apply to only a few customers. Depending on their location, varying customers may use more or less of the Company’s 138 kV lines, which is true of customers that do not own their own substations. 5 TR 1698. It is neither manageable nor desirable to attempt to design rates to accommodate all such differences by developing a distinct rate for each customer. 5 TR 1698.

Ms. Alderson based her proposal, in part, on the Company’s response to discovery request 20134-HSC-CE-429, which stated that the “total length of all 138kV distribution lines owned by Consumers Energy that directly connect to a customer-owned 138kV substation is 14.16 miles.” See Exhibit HSC-1, page 32. However, Company witness Anderson explained that the correct number of substations connected to this 14.16 miles of line is nine, and it is not accurate to assert that this discovery response supports a conclusion that these substations are served only by the 14.16 miles of line because the response does not address the connection of the opposite end of the lines. 5 TR 1993. The Commission should not include in the substation ownership credit Ms. Alderson’s calculation of the portion of the 138 kV lines that are used by Voltage 1 customers.

Ms. Alderson also proposed an offset for shared administrative and general expense and common and intangible plant costs. 6 TR 2235-2236. These costs are not related to customers owning a substation, and as such customers that own substations are no less responsible for these costs than customers served by Company-owned substations. 5 TR 1699. The substation ownership credit takes into account costs related to owning the substation, including the assets' ROE, depreciation, O&M expenses, and property taxes. 5 TR 1699. An additional offset for these identified costs is not warranted.

Another concern with HSC's proposed revisions to the substation ownership credit is that they do not reflect information provided to HSC in discovery that the Company does not include ROA distribution maximum demand units in the calculation of the credit. 5 TR 1697-1698. Including such an ROA adjustment would be appropriate because ROA customers are also eligible to receive substation ownership credits. 5 TR 1698. Including the ROA distribution, maximum demand units would result in revising the denominator of the credit calculation (i.e., the Max Demand) to 10,549 MW for Voltage Level 1 and 8,749 MW for Voltage Level 2. 5 TR 1698. Even if the Commission adopted all of HSC's proposed adjustments, which it should not, the credit per MW for Voltage Levels 1 and 2 would still be less than the credits proposed by the Company if this ROA adjustment was included. 5 TR 1698. At this time, Consumers Energy is not proposing that the Company adopt this change, but rather recommends that the Commission adopt the methodology for calculating the substation ownership credit that the Company used in this proceeding, which is consistent with the methodology approved in Case No. U-18322. 5 TR 1698.

B. Rate Design And Rate Tariff Issues

Company witness Collins, Principal Rate Analyst - Lead in the Pricing section of the Rates and Regulation Department, supported the Company's position concerning rate design. As Ms. Collins testified, "the main objectives in designing rates are to: (i) establish rates that adhere to the cost of service as required by 2008 Public Act 286 ('Act 286'); (ii) establish rates that promote efficient use of the Company's electric system and promote customer energy efficiency; (iii) establish rates that promote a favorable business climate while meeting the other stated objectives; and (iv) provide the Company with a fair opportunity to collect its revenue requirements." 5 TR 1555.

Ms. Collins provided the following overview of the Company's rate design proposals:

"Q. Please describe the Company's approach to rate design in this case.

"A. Generally, the Company has designed rates so that the revenue recovered from each customer class reflects the adjusted costs for that class in the Company's test year Cost of-Service Study ('COSS') as provided by Company witness Josnelly C. Aponte. The proposed electric revenue and associated rate increases for each rate class are shown on Exhibit A-16 (LMC-1), Schedule F-2.

Residential Rates

"The Company is proposing a long term redesign of residential rates. The Company is proposing changes to its existing Residential Service Secondary Rate ('RS') to conform to the March 29, 2018 Order in Case No. U-18322. The Company is also proposing to eventually eliminate the Residential Service Time of Day Rate ('RT'), Experimental Residential Plug-In Electric Vehicle rates, ('REV-1' and 'REV-2') and demand response rates, Residential Dynamic Pricing ('RDP'), and Residential Dynamic Pricing Rebate ('RDPR'). The Company is proposing to establish two new time of use rates and to modify options for participation in the Peak Power Savers Peak Reward Program to replace the eliminated rates.

“Secondary Rates

“The Company is proposing to maintain its existing secondary rates, General Service Rate (‘GS’), General Service Demand Rate (‘GSD’), and General Secondary Time of Use Rate (GSTU’).

“Primary Rates

“The Company is proposing to maintain its existing primary rates, General Primary Rate (‘Rate GP’), General Primary Demand (‘GPD’) Rate (‘Rate GPD’), Energy Intensive Primary Rate (‘EIP’), and General Primary Time of Use Rate (‘Rate GPTU’). The Company is proposing a new market-based interruptible pilot provision for Rate GPD, which will be offered in addition to the Company’s current Interruptible Provision GI.

“Self-Generation Rate

“The Company is not proposing any changes to its existing Self-Generation Rate (‘GSG 2’) Rate.” 5 TR 1556-1557.

Ms. Collins’ Exhibit A-16 (LMC-4), Schedule F-4, provided the impacts that would result from the proposed electric rates and rate design changes for customers on each rate schedule at various usage levels.

Ms. Collins also provided, in Exhibit A-68 (LMC-5), an illustrative calculation of the proposed IRM surcharge, showing how the Company would collect the revenue requirements associated with the IRM. The revenue requirements associated with the IRM are based on a demand or energy surcharge for each of the rate schedules. The revenue requirement for each class is based on the cost allocation of the revenue requirements in Exhibit A-32 (JCA-5). The rate design for the various voltage levels for Rates GP, GPD, EIP, and GPTU, are consistent with the rate differentials used the Company’s rate design. The surcharge is based on test year sales and would apply to both Full Service and ROA customers. With approval of the Commission,

these rates would be effective for service rendered on and after January 1, 2020, and service on and after January 1, 2021. The IRM surcharges would continue until rates were modified in the Company's next electric case. 5 TR 1575-1576.

Staff witness Isakson proposed certain adjustments to the Company's rate design to update for: (i) the June 11, 2018 Errata Order in Case No. U-18322; (ii) the June 28, 2018 Rehearing Order in that same case; and (iii) the July 24, 2018 Order in Case No. U-20102 (for the TCJA). 6 TR 2349-2350. Ms. Collins testified that she agreed with these adjustments, and she sponsored Exhibits A-143 (LMC-7) through A-145 (LMC-9), which updated the rate design based on the changes. 5 TR 1581. The updated rate design in Exhibits A-143 (LMC-7) through A-145 (LMC-9) also reflect the revised revenue requirement presented by Company witness Myers in her rebuttal testimony, and other revisions that are discussed in more detail below.

Staff and various intervenors took positions with which the Company does not agree. These additional positions are without merit for the reasons provided below, and the Commission should reject them. The Company's requested rate design and requests for other approvals are discussed below.

1. Residential Rates

a. Transition Of Customers From Residential Rate RS To Residential Summer On Peak Rate

The Commission's March 29, 2018 Order in Case No U-18322, page 106, directed the Company as follows:

"In accordance with the findings and conclusions discussed above, Consumers shall, in its next general rate case, eliminate the inverted block rate and replace it with a summer, on-peak, noncapacity rate for residential customers. Consumers shall also include a proposal for allowing customers who opt out of AMI to retain the existing rate structure."

Ms. Collins testified that, in accordance with this requirement, the Company's rate design reflects the elimination of the Residential Rate RS inverted block rate and its replacement with the Summer On Peak Rate. 5 TR 1562.

The proposed Summer On Peak Rate has weekday on-peak pricing from 2 P.M. to 7 P.M. from June 1 to September 30 of each year. Consumers Energy developed the on-peak time period based on its examination of the total Company system load profile, as well as its Residential load profile. It also considered the hourly LMP forecast to ensure the increase in LMP corresponded to the system peak hours. 5 TR 1562; Exhibit A-16 (RLB-2), Schedule F-5, pages 15-18. All other hours would be priced equal to the non-Summer rate. *Id.*

Ms. Collins testified that, as customers start to respond to price signals under the new rate, the Company anticipates they will start to shift usage away from the on-peak period, and that she reflected this anticipated behavior change in the rate design. 5 TR 1562-1563. To develop the total residential Summer usage, the Company added the Summer sales forecast for the Rate RS first 600 kWh and excess kWh. Then the three year average hourly load profile was used to split the total residential Summer usage into on-peak usage and all else. From this, the Company shifted 14% of the on-peak usage into the remaining block in order to recognize the behavior change from customers on this rate. The Company determined that 14% was the appropriate amount of usage to shift from the on-peak period based on research results supplied by The Cadmus Group, LLC, which detail the customer behavior impacts experienced in our dynamic pricing Rates RDP and Residential Dynamic Pricing Rebate ("RDPR"). 5 TR 1563.

Company witness Hall originally testified that completion of the IT system configuration necessary to implement the Summer On Peak Rate for 1.6 million customers would be a 12-to-16 month endeavor. 2 TR 277-278. The Company later provided an updated implementation

timeline in discovery, which was admitted as Exhibit S-17. The updated timeline proposed that, given the scale of the project, the Company would test system design and integration, online customer apps and tools, and customer acceptance through a targeted pilot beginning in June 2019. The pilot would continue through December 2019 to enable evaluation of the changes in customer electric use behavior following the Summer season. Following a successful pilot, all remaining 1.6 million residential customers with AMI meters would be transferred to the new Summer On Peak Rate on January 1, 2020. *Id.*

Staff witness Isakson testified that Staff accepted the Company's updated timeline for the implementation of the Summer On Peak Rate. 6 TR 2351-2353. Mr. Isakson also proposed a transitional rate for residential customers, set forth in Exhibit S-6, Schedule F-3 (page 2), that retained the same previously-approved inverted block rate design, updated with billing determinants for the current Rate RS customers (instead of only opt-out customers). The transitional rate would be for customers who, in the test year, have not been transitioned to the Summer On Peak Rate. After the transition, the Residential Service RS Smart Meter Opt Out rate, Exhibit S-6, Schedule F-3, page 3, would be available for customers who opt-out of having a smart meter. 6 TR 2353.

Ms. Collins testified that Consumers Energy agreed to Staff's proposed transitional rate. 5 TR 1581. This transitional rate should apply to all Rate RS customers who have not yet been moved to the new Residential Summer On Peak Rate prior to January 1, 2020. This would include AMI opt-out customers and customers on specialized programs (such as Paygo and Net Metering) that will take longer to configure in the Company's billing system and transition to the new rate than the standard Rate RS residential customer. 5 TR 1581-1582.

Consumers Energy submits that its Summer On Peak Rate, and its Staff-supported updated transition plan, are reasonable, meet the requirements of the Commission's March 29, 2018 Order in Case No U-18322, and should be approved.

b. Request For Approval Of UPR Provision And Other Residential Rates

(i.) Request For Approval Of UPR Provision

The Commission should approve the Company's UPR provision for all the reasons provided in Section III.A.6.b. of this Initial Brief.

(ii.) Request For Approval Of Other Residential Rate Changes

Consumers Energy requests approval to maintain, for the present, its existing residential Rates RT, REV-1, REV 2, RDP, and RDPR, as updated to reflect the current rate differentials and new revenue requirement. 5 TR 1564. The Company also proposes a long term strategic plan to streamline and simplify residential rates. Ms. Collins provided numerous reasons for the changes. First, the Company currently has six different residential rate options in place, five of which are TOU rates with an on-peak time periods that are not aligned. Additionally, Rates RDP and RDPR are both dynamic pricing options, but one offers a reward and one has a penalty. Further, a customer who wants to reduce his or her bill through AC Peak Cycling Program must be on the standard residential rate, while a customer who wants to participate in dynamic pricing has to move off the standard residential rate. These differing options, time blocks, and provisions can cause confusion for customers, and the transition of Rate RS customers to the Summer On Peak Rate will add another layer of complexity and confusion. 5 TR 1564.

The Company therefore proposes to simplify its residential rate options, over a two-to-three year period, to eliminate the existing RT, RDP, RDPR, and REV 1 and 2 rates, and introduce three distinct rate options. 5 TR 1565. The COSS currently breaks residential service

into two columns, Rate RT and all others. As part of its residential rate simplification strategy, the Company would combine all of the residential class into one cost column, and then design the three new residential rates to each collect that same average power supply cost on a \$/kWh basis for energy used during the same time period. *Id.* The first new residential rate would be the Summer On Peak Rate, discussed above.

The second new residential rate would be the Residential Smart Hours Rate, which is a two period year-round TOU rate with an on-peak period from 2 P.M. to 7 P.M. year-round. The Company would move current customers of Rates RT, RDP, and RDPR to this new rate. Customers on this rate would also be able to participate in the UPR, thus enabling them to receive rewards for any reductions in energy use during a critical peak period, and which would provide them additional opportunity to reduce their energy costs. Customers on this rate could also choose to enroll in the Peak Rewards AC Peak Cycling Program provision. 5 TR 1565.

The third new residential rate would be the Nighttime Savers Rate. This would be a year-round three-period TOU rate, to which the Company would transition all existing Rate REV-1 and REV-2 customers. 5 TR 1566. It would encourage energy usage during the Super Off Peak period, from 11 P.M. to 6 A.M., and would be ideal for EV customers. It would also maintain the 2 P.M. to 7 P.M. year round on-peak period, and thus would keep the Company's on-peak hours consistent for all residential customers. Customers on the Nighttime Savers Rate could also participate in the UPR provision, and would also have the option to add the Peak Savers AC Peak Cycling Program provision. Customers who have electric charging stations at their home could choose to have the Nighttime Savers Rate separately metered from their main household meter. Similar to the current Rate REV-2, this separately metered rate would not require an additional system access charge. 5 TR 1566.

MEC/NRDC/SC/EC witness Baumhefner proposed an increase to the on-peak to off-peak price ratios of the Nighttime Savers Rate by lowering the off-peak and super off-peak prices. 6 TR 2695-2697. Ms. Collins testified that the Company agreed that a larger differential between the off-peak and super off-peak rates would further incent customers to use during off-peak hours. 5 TR 1590. She therefore increased the differential to lower the super off-peak rate for both the Nighttime Savers rate and REV rate, and reflected them in Exhibits A-143 (LMC-7) through A-145 (LMC 9).

Consumers Energy proposes to transition customers to these new rates over a period of two to three years. 5 TR 1566. The Company's first priority will be to configure the billing system for the Summer On Peak Rate as quickly as possible. Once that programming and migration are done, the Company would initiate the IT work on the Smart Hours Rate and Nighttime Savers Rate configurations, and migrate customers to those rates as they became available in the billing system, and after they receive advanced notice. As the transition of these customers would occur outside of the test year, Ms. Collins populated the new rates in the rate design model for purposes of this case. Exhibit A-16 (LMC-3), Schedule F-3, pages 8 and 9, shows the rate design for these new proposed rates.

Company witness Rachel L. Brege testified that, following configuration of the new rates, and their planned availability in early 2021, the Company would transition customers to either the Residential Smart Hours Rate or Residential Nighttime Savers Rate, terminate and remove the old rates from its Electric Rate Book. 5 TR 1626-1627. See Exhibit A-16 (RLB-2), Schedule F-5 pages 31-34 (Residential Smart Hours Rate), pages 35-39 (Residential Nighttime Savers Rate). Ms. Collins testified that approval of these changes in this case is important because the Company must be able to plan rate changes over the next two to three years, which

will help identify the resources necessary, prioritize the work, plan the customer communications, and ensure that the necessary customer support is in place to make this a smooth and positive transition for customers. 5 TR 1566-1567. Ms. Brege likewise testified that approval of the tariffs will help the Company prioritize billing changes, plan and prepare customer communications, and set the infrastructure in place to support rate transitions. 5 TR 1626-1627.

As discussed above in Section III.A.6.a.(ii), the Company also requests approval of changes to the Peak Power Savers AC Peak Cycling Program rate to increase the credit to \$8.00 per month for the Summer months, with credits allocated to other customers based on the manner in which the Test Year COSS allocates total capacity costs. 5 TR 1567. Staff witness Isakson testified in support of corrections to the proposed rate design in order to include the residential AC Peak Cycling Program credits in the allocation of interruptible capacity costs. 6 TR 2369. Ms. Collins testified that Consumers Energy agreed to the correction. 5 TR 1582.

The Company is proposing to continue the Senior Citizen and Income Assistance provisions offered under the Rate RS, Residential Summer On Peak Basic Rate and Rate RT rate schedules. The Income Assistance credit is equivalent to the monthly System Access charge, and the Senior Citizen provision is set as a credit of 50% of the monthly System Access charge. 5 TR 1568. The rate impacts for each residential rate schedule are shown on Exhibit A-16 (LMC-1), Schedule F-2, page 1, which shows the proposed rate increase of 1.4% in total for the residential class, as indicated on line 5, column (e). The Company is proposing that all residential rates pay the same distribution and system access charges. The Company is proposing an increase to the Residential System Access charge from \$7.00 per month to \$7.50 per month, based on the results of the COSS sponsored by Company witness Aponte. *Id.*

As discussed above, Ms. Collins addressed the issues raised by Mr. Isakson and Mr. Baumhefner. The Company submits, therefore, that the Commission should approve the Company's changes to residential rates, modified as discussed above.

2. General Service Secondary Rates

Consumers Energy proposes to keep the same basic rate designs as currently approved for Rates GS and GSTU, with updates for Summer-Winter differentials based on an updated average of both historic and forecasted MISO LMPs at the Company's load node. 5 TR 1569. The Company separated all power supply charges into capacity and non-capacity charges to align with Section 6w of Act 341. This methodology is consistent with the Company's approach in its previous electric rate case, Case No. U-18322. With regard to Secondary Rate GSD, in light of the requirement of Section 6w of 2016 Act 341 to break out capacity costs for use in developing a SRM, the Company designed the peak demand charge to collect 100% of the capacity costs. The rate impact for the General Service Secondary Class if the Commission were to approve the Company's proposed rates would be a 1.2% increase, which includes Rates GS and GSD. 5 TR 1569; Exhibit A-16 (LMC-1), Schedule F-2, page 1, line 11.

3. General Service Primary Rates

a. Rate GP

The Company proposes to keep the same basic rate design for Rate GP as currently approved, updated to reflect revised price differentials based predominantly on the average historical and forecasted LMPs and the new revenue requirement target. The Company separated all power supply charges into capacity and non-capacity charges to align with Section 6w of Act 341. 5 TR 1569-1570. The rate impact for the total Rate GP customers would be a 5.6% decrease. 5 TR 1570; Exhibit A-16 (LMC-1), Schedule F-2, page 1, line 12.

b. Rate GPD

Consumers Energy requests approval to add an additional interruptible rate option, called Interruptible Service Provision – Market-Price Option (“GI2”), to its Rate GPD. The Company developed the GI2 provision in response to customer interest in a market-based interruptible option, which provides customers with a built-in incentive to reduce energy when the LMP is elevated. 5 TR 1571. The new option would allow a GPD customer to subscribe a portion of its load to the GI2 provision. The Company would bill the customer for capacity and transmission on a per kWh basis, as well as the MISO LMP energy cost. The capacity and transmission would be the same as all other Rate GPD customers, but with a per kWh reduction based on the interruptible credits. The Company proposes to increase the overall cap for interruptible to 400 MW, and modeled 200 MW on the standard GI provision and 200 MW on the GI2 provision. The Company did not propose any additional changes to the basic rate design for Rate GPD customers, other than updates to reflect the revised revenue requirement and price differentials. *Id.*

Staff witness Isakson recommended changing the Rate GP/Rate GPD crossing point adjustment to increase the load factor crossing point from 45% to 50%, and further recommended that the Commission continue to adjust this crossing point until the Company moves customers between rates such that the adjustment is no longer needed. 6 TR 2366-2367. The Commission should not adopt these changes at this time. As Ms. Collins testified, the Company designed Rates GP and GPD by following the same methodology approved in Case Nos. U-17990 and U-18322. 5 TR 1582. Further, Mr. Isakson’s position does not account for the complexities involved in such an adjustment. Ms. Collins explained these complexities, and that changing the crossing point is a cyclical process that involves a high amount of uncertainty:

“In order to identify which customers would be impacted by a crossing point adjustment, the Company must first run the complete sales forecast, cost of service, and rate design assuming no adjustment to maintain the crossing points between Rate GP and Rate GPD. From there, the Company can determine which customers would benefit from moving to a different rate and then adjust the sales forecast accordingly by migrating customers to the more economic rate. Then a new cost of service and rate design must be calculated based on the new determinants, as well as updated present revenues. However, even if the Company identifies customers that would be better off on a different rate, these customers do not always transition to the more favorable rate. Per the Company tariffs, customers have the right to choose their own rate. Thus, the Company cannot move customers between rate schedules, even if it is in their best interest. The Company will have to reach out to the impacted customers and discuss their rate options. The Company runs the risk of collecting too much, or too little revenue when customers do not transition to rates based on the Company’s forecast.” 5 TR 1583.

As a result, the Commission should not adopt Staff’s position on the Rate GP/Rate GPD crossing point, as it does not account for all the relevant factors, including the fact that customers may choose not to change rates despite the crossing point adjustment.

However, as Ms. Collins explained, in its next rate case filing, Consumers Energy will endeavor to identify customers that would be impacted by minimizing the crossing point adjustment and migrate the customers to the more economic rate. 5 TR 1582-1583. The Commission should, therefore, not adopt Staff’s proposed Rate GP/Rate GPD crossing point adjustment, and instead permit the Company to further analyze the potential for adjustment, and offer its own proposal (if sensible) in a future rate case.

ABATE witness Pollack recommended a correction to the Company’s rate design to spread the GI2-related credits to all customers in a manner similar to the GI credits. 7 TR 3497. Ms. Collins testified that Consumers Energy agreed that the interruptible credit for GI2 should have been spread to all customers, comparable to the way credits are handled for GI. 5 TR 1584.

She included the correction in her updated rate design, Exhibits A-143 (LMC-7) through A-145 (LMC-9).

HSC witness Alderson asserted that the Company's proposed distribution charges are not cost based. 6 TR 2240. This claim is without merit, and the Commission should reject it. Ms. Collins testified that the Company's calculation of distribution charges for Rate GPD was based on the cost of service by voltage level. The calculation starts with the demand and customer related distribution costs by voltage level from the cost-of-service study. For Rates EIP and GSG-2, where the distribution is not separated by voltage level, the distribution is broken into voltage level based on demands. From this total distribution by voltage level, the system access revenue, substation ownership credit offset, and GEI credit offset are subtracted to get a total distribution amount per the voltage level. This total distribution amount by voltage level is then divided by the demands to calculate a cost-based distribution rate. In addition, Ms. Alderson did not include Rates EIP and GSG-2 in her calculations, but these rates pay the same distribution charges as Rates GPD and GPTU and should be included in the calculation. When Ms. Collins put Ms. Alderson's proposed distribution rates into the filed rate design model, it produced \$3 million less than the revenue requirement. 5 TR 1585-1586. In light of these deficiencies, the Commission should reject the distribution charges proposed by Ms. Alderson.

Kroger witness Bieber proposed to revise the Rate GPD rate design. According to Mr. Bieber, his revision was needed to more closely align revenues from Rate GPD Voltage Level 1 and Rate GPD Voltage Level 3 to the rate design targets. 5 TR 1391. The Commission should reject his revision. MCL 460.11 requires cost-based rates by customer class, and Ms. Collins testified that the rates for Rate GPD were cost-based within the class. 5 TR 1586.

Ms. Collins further testified that differentials must be maintained within the class voltage levels to recognize that higher voltage customers are connected to the Company's system, where less Company infrastructure was required to serve them and to recognize line losses for each voltage level. *Id.* This is done by combining the cost of service GPD voltage levels in one bucket, and using the differences from the cost of service study to determine how the rates would increase among the three voltage levels. 5 TR 1595. Mr. Bieber's revisions are without merit and the Commission should reject them.

Staff witness Isakson recommended that the Company increase the non-interruption charge for the Company's proposed GPD GI2 provision from \$10 per kW to \$50 per kW. 6 TR 2368-2369. Ms. Brege explained why the Commission should not adopt this recommendation:

“Q. Staff Witness Isakson recommends that the Company increase the non-interruption charge for the Company's proposed GPD GI2 provision from \$10 per kW to \$50 per kW. Do you agree with this recommendation?

A. No. The Company believes a non-interruption charge of \$10 per kW for the highest 15 minute kW of Interruptible On-Peak Billing Demand created during the interruption period, in addition to the prescribed monthly rate, is appropriate for GI2. While the Company believes that a penalty is necessary to ensure that the customer provides the interruptible resource when it is called upon, it does not want the penalty to be so punitive that it unnecessarily discourages customers from participating in the program. The Company is relying on the interruptible provisions to help provide a future planned demand response, which can be a cost-effective capacity resource. The Company believes it is important that customers do not perceive the risk of the penalty as a barrier to participation. In addition, the Company has structured the GI2 similar to DTE's Rider 10, which has a \$10 per kW per month penalty, according to DTE Electric Company's Fourth Revised Sheet No. D-92.00. As the Company's GI2 is similar to DTE's Rider 10, we believe an equitable penalty is appropriate.” 5 TR 1631-1632.

Thus, a \$50 penalty is too high and would risk creating a barrier to participation. Consumers Energy's \$10 penalty is consistent with what the Commission has approved for DTE Electric Company, and the Commission should approve it.

c. Rate GPTU

Consumers Energy proposes to keep its current approved Rate GPTU rate design, but update the price of each time block to reflect the Company's proposed rate design revenue target and price differentials, and to separate the power supply charges into capacity and non-capacity charges. 5 TR 1571-1572. Ms. Collins testified that Rate GPTU is not currently separated within the COSS. The Company began developing the corresponding load profiles by voltage level using 2015 historic data, and it will evaluate the appropriateness of developing a separate cost column in the COSS once three years of load profile data are available. Currently, the Rate GPTU costs are included in the Rate GPD column in the COSS. The Company determined the power supply costs for Rate GPTU when it separated the customers on this rate from the Rate GPD costs through Company witness Breuring's projection of the energy and on-peak capacity determinants for Rate GPTU customers. Using those projections, the Company allocated a proportional amount of power supply costs from the Rate GPD Schedule to the Rate GPTU Schedule and designed rates accordingly. 5 TR 1572.

d. Rate EIP

The Company is proposing to keep the current approved rate design for Rate EIP, with updates to reflect revised price differentials for each time block used in the rate based predominantly on an average of historical and forecasted LMPs and the new revenue requirement target. 5 TR 1572.

e. **Rate GSG-2**

Ms. Collins testified that, as required by the Commission’s March 29, 2018 Order in Case No. U-18322, the Company provided actual and projected peak metered demand billing determinants for its Large Self Generation Rate, Rate GSG-2, customers, including any applied ratchet. 5 TR 1573. The actual peak metered demand billing determinants for the calendar year 2017 are shown in the table below, and were also used as the projected demand billing determinants shown on Exhibit A-16 (LMC-3), Schedule F-3, page 25.

January 2017 to December 2017	
<u>Rate</u>	<u>OnPk kW</u>
GSG_1330V1	9,576
GSG_1330V3	2,021
GSG_1350V1	51,012
GSG_1350V2	<u>98,258</u>
Total	160,867

Ms. Collins also addressed the requirement in the March 29, 2018 Order in Case No. U-18322 that: “if the Company chooses to rely on contracted demand, Consumers shall provide justification for its departure from the standardized framework.” In her direct testimony, Ms. Collins testified to the basis for relying on contracted demand, as the delivery charges for Rate GSG-2 are assessed based as a per kW charge for contracted Standby Demand. 5 TR 1573. The justification would be that contracted demand is the amount of capacity the Company must stand ready to serve if a GSG-2 customer needs service. The Company must also have distribution systems in place to serve this potential load. Therefore, as Ms. Collins explained, standby customers are appropriately charged delivery based on the contracted standby capacity. *Id.*

In addition, the Company looked at the contracted demands versus the actual demands for 2017, and did not find a large difference. 5 TR 1574. This is because most standby customers

take standby service at some point for maintenance or unforeseen circumstances within a given 12-month period. During the time the customer’s generating unit is not operating or operating at reduced levels, they establish a Maximum Demand. Customers under the standard GPD Rate are billed on their highest Maximum Demand for the current month or preceding 11 months. The table below shows the contracted demands versus the actual demands for calendar year 2017:

	2017		
	Contracted	Actual	% of
	Capacity	Demand	Contracted
	(kW)	(kW)	
GSG_1330V1	36,036	36,036	100%
GSG_1330V3	478	453	95%
GSG_1350V1	104,833	93,343	89%
GSG_1350V2	9,386	8,227	88%

Staff witness Kevin S. Krause recommended that the Company base its Rate GSG-2 Maximum Demand charges on measured demands, rather than on the contracted amounts. 6 TR 2470-2471. In the interest of compromise, the Company agrees to Mr. Krause’s recommendation. Ms. Collins therefore testified in rebuttal that the Company would agree to charge GSG-2 customers for distribution based on the same measured Maximum demand (the highest 15-minute demand created during the current month or previous 11 months) as customers served on Rate GPD. 5 TR 1583.

MEC/NRDC/SC/EC/MEIBC witness Jester took the position that the Rate GSG-2 standby capacity rate should be set based on the Cost of New Entry (“CONE”), rather than the highest contracted capacity cost as is currently the case. 6 TR 2653. MEIBC witness Jamie W. Scripps also took this position. 7 TR 3101. The Commission should reject this position as without merit. First, as Ms. Collins testified, Consumers Energy must plan and secure capacity for all its retail customers, including customers served on standby rates. 5 TR 1587. Because

Consumers Energy has adequate capacity and plans for capacity for all of its retail customers, CONE does not reflect the Company's actual costs. Second, if GSG-2 standby capacity rate were updated at all, it should be to base them on the Company's approved embedded cost of capacity on a per kW basis to remove the subsidy that GSG-2 standby customers are receiving today on Power Supply. *Id.* As the Company plans capacity for all customers and therefore does not need to purchase additional capacity for standby customers, GSG-2 customers should pay for the cost of capacity that has been secured to provide service based on the allocation for capacity as approved by the MPSC. 5 TR 1588.

MEC/NRDC/SC/EC/MEIBC witness Jester asserted that (i) Rate GSG-2 standby delivery charges should be set based on the actual demand times of the approved standby charges, prorated based on the number of on-peak days that standby service was used, and (ii) an additional standby demand charge that would be assessed that reflects the additional cost of facilities that are either exclusively or primarily used to serve the customer's standby requirements. 6 TR 2654. The Commission should reject these positions. As discussed above, the Company agrees to Staff's proposal to charge Rate GSG-2 Maximum Demand based on actual metered demands in the same manner that Rate GPD customers are subject to. However, as Ms. Collins testified, there is no justification to prorate the Maximum Demand charge based on the number of on-peak days standby service was used. 5 TR 1588. Demand charges are an accepted and reasonable approach to the collection of distribution fixed costs. As Ms. Collins further explained, there is no reason to treat standby customers any differently than full requirement customers. *Id.* To prorate a Rate GSG-2 customer's distribution charges would only create a subsidy for which all other customers would have to pay. The Company must build the distribution system to accommodate the customer's full standby requirements, and it is only

reasonable that the customers pay for these facilities that are in place to serve them. If Rate GSG-2 customers pay the Maximum Demand charge based on their actual use, no reason exists to calculate the additional cost of facilities charge as Mr. Jester proposed. 5 TR 1588-1589.

The Commission should also reject MEIBC witness Scripps' position that the monthly delivery charges for Rate GSG-2 should be prorated based on the forced outage rate of the customer's generating system. 7 TR 3098. As Ms. Collins testified, the cost of the distribution facilities in place to serve a customer does not change based on the amount of time the customer uses the system. 5 TR 1589. Ms. Scripps did not show that the investment in distribution facilities is related to the customer's forced outage rate. Applying a proration to distribution charges would not be consistent with cost-based ratemaking and would unnecessarily create cross subsidies. *Id.* Non-standby customers should not be responsible for the distribution costs of standby customers and therefore the Commission should reject MEIBC's proposal.

Ms. Scripps also took the position that the Company should differentiate between scheduled/maintenance and unscheduled outages in Rate GSG-2 by charging customers lower power supply capacity and energy rates for Scheduled/Maintenance outages. 7 TR 3099. The Commission should reject this position as without merit. Ms. Collins explained that Consumers Energy already considers the capacity charges for GSG-2 standby as being subsidized. 5 TR 1589. Consequently, to differentiate the cost-based differential between these two types of services not be sensible. It would be more appropriate for these customers to avoid the capacity charges for standby service by avoiding using capacity during the On-Peak hours in which it is incurred. *Id.*

4. Streetlighting Rates

Rates GUL, GML, GU-XL, and GU comprise Consumers Energy's streetlighting rates. The Company is not requesting any changes to Rates GUL, GML, GU-XL, or GU, apart from rate updates to reflect the new revenue requirement targets. 5 TR 1574.

MEC/NRDC/SC/EC/MEIBC witness Jester suggested that the Company provide an option for a municipality to finance the conversion to LED streetlighting. 6 TR 2747. The Commission should reject this suggestion for the reasons provided by Company witness Brege:

“Financing is not a core service of Consumers Energy and this suggestion will implicate the Code of Conduct, which applies to all utilities and alternative electric suppliers in Michigan. The Company does not have systems in place to offer financing options for a municipality to convert to LED streetlighting, nor does the Company's billing system have the appropriate configuration in place to bill municipal streetlighting customers for financing. The Company does not have the available resources necessary to undertake modifying its systems to offer financing options for streetlighting conversions at this time, as it is prioritizing the configuration work necessary to modify its residential rates, including implementation of the required transition to the Residential Summer On-Peak Basic rate.” 5 TR 1634.

5. Educational Institution Rate

Ms. Collins addressed the Company's proposed Education Institution Rate and compliance with MCL 460.11(3)²⁷ to ensure public and private schools, universities, and community colleges are charged retail rates that reflect the actual cost of providing service to those customers. 5 TR 1555. Consistent with the methodology approved by the Commission in the Company's previous electric rate cases, including Case No. U-18322, the Company proposes

²⁷ MCL 460.11(3) provides:

“Notwithstanding any other provision of this section, the commission shall establish rate schedules that ensure that public and private schools, universities, and community colleges are charged retail electric rates that reflect the actual cost of providing service to those customers. Electric utilities regulated under this section shall file with the commission tariffs to ensure that public and private schools, universities, and community colleges are charged electric rates as provided in this subsection.”

to continue to provide all Educational Institution customers with a credit that removes the subsidies for Income Assistance and Senior Citizens. 5 TR 1574. This ensures that Educational Institution customers pay a cost-based rate without subsidies that is always lower than the other general service customers served at the same voltage level.

6. Substation Ownership Credit

The Company updated its substation ownership credit amounts, based on the COSS, and reflected them in rate design for Rates GPD, EIP, GPTU, and GSG-2. 5 TR 1572; Exhibit A-16 (RLB-2), Schedule F-5.

HSC witness Alderson recommended that the Company set substation ownership credits on a percentage of the total distribution charge. 6 TR 2229-2232. The Commission should reject this proposal. The methodology for determining the substation ownership credit was established in Case No. U-17990 and is based on the cost of service. 5 TR 1586. Ms. Collins testified in rebuttal that to set the substation ownership credit on a percentage of the distribution demand charge would ignore the cost of service methodology approved by the Commission. This rebuttal testimony was not impeached, nor did Ms. Alderson provide justification for a departure from the methodology for determining the substation ownership credit established in Case No. U-17990.

HSC witness Alderson recommended that recovery of the Substation Ownership Credit be shared across all other classes, just as the interruptible credits are today. 6 TR 2241-2242. Ms. Collins testified that she agreed. 5 TR 1585. She included the change in her updated rate design, Exhibits A-143 (LMC-7) through A-145 (LMC-9).

7. Conclusion

The Commission should approve the Company's rate design for General Service Primary Rates, with the modifications to which the Company agreed, as discussed above. The Staff and

Intervenor positions with which the Company does not agree are without merit, and the Commission should reject them.

C. Other Tariff Issues

1. Request For Approval Of Change To Rule C4.4 – Resale

Ms. Brege testified in support of a change to Rule C4.4 – Resale in the Company’s Tariff, to increase the penalty for resale customers that do not meet the annual audit and meter testing requirements:

“Resale customers have an annual audit and meter testing requirement. When these requirements are not met, the current Commission-approved tariff gives the Company the authority to impose a penalty equal to 5% of the resale customer’s bill, not including taxes, until the customer complies with the Resale requirements. I am proposing to increase the penalty from 5% to 15% per month until the customer has complied with the Resale requirements. The intent of the increase of the penalty percentage is to motivate the Resale customer to comply with the audit and meter testing requirements. These requirements help ensure that ultimate customers, who receive service through Resale, are being properly billed for energy consumption and to ensure the energy consumption is properly metered. In addition, the Company is proposing to allow Resale service on General Service Secondary Time-of-Use Rate GSTU and General Service Primary Time-of-Use Rate GPTU to satisfy customer requests.” 5 TR 1625.

As no party witness testified in opposition to this change, the Commission should approve it.

2. Request For Approval Of Change To Billing Of Residential Power Supply Energy Charges

Ms. Brege testified in support of a change in how Summer Power Supply Energy Charges will be billed for residential customers with a transmitting meter. She explained the nature of the problem that the change would address:

“Power Supply Energy Charges are currently billed on a billing month basis. Summer includes the billing months of June through September, while non-summer includes the billing months of October through May. Each billing month has 21 portions which

results in varying dates in the consumption period by billing portion. The fluctuating consumption period makes it difficult to communicate to a customer when summer rates are being billed versus non-summer rates. For example, a residential customer being billed on Portion 1 of the June 2018 bill month has an invoice generated the evening of May 31, 2018. The customer is paying Summer Power Supply Energy Charges even though the invoice does not have any consumption during the calendar month of June – the customer’s energy use in this circumstance actually reflects May’s energy consumption.” 5 TR 1627-1628.

The Company proposes to align Power Supply Energy Charges with calendar days instead of billing portions, and thus the Summer On-Peak Power Supply charges would reflect June 1 through September 30 energy consumption for all customers, every year. This change would also align Summer Power Supply Energy Charge billing with the UPR, which also has a timeframe of June 1 through September 30. This change will better align the Company’s effort to modify customer’s energy use with the Summer peak energy use months.

As no party witness testified in opposition to this change, Consumers Energy submits that the Commission should approve it.

3. Request For Approval Of Change To Wireless Under Glass Meter Language In Tariff

Consumers Energy also requests to include new Wireless Under Glass Meter language on Tariff Sheet Nos. E-6.00, E-7.00, E-20.00, E-22.00, E-24.00, E-25.00, and E-27.00. The Company is replacing ROA meters that are dependent on a telephone line to transmit consumption and demand data with Wireless Under Glass meters by 2020. Telephone providers are transitioning existing phone lines from analog to digital. Digital phone lines are not compatible with our current ROA meters. Approximately half of the electric customer choice meters will be replaced in 2019, and the remaining electric customer choice meters will be replaced in 2020. 5 TR 1628. Therefore, the Company has added language that such services will be metered with a Wireless Under Glass Meter.

As no party witness testified in opposition to this change, Consumers Energy requests that the Commission approve it.

4. Request For Approval Of Remaining Tariff Changes

The Company requests approval of the tariff changes summarized in Exhibit A-53 (RLB-1), and sponsored by Ms. Brege. The Company also agrees to language substantially similar to Staff Witness Ozar's proposed tariff language that will suspend a contribution in aid of construction for AC Level 2 or DC Fast Charge sites participating in the PowerMIDrive pilot. 5 TR 1632. Thus, the Company would include such language in its filed tariff.

5. Non-Transmitting Meter Tariff

In the Commission's February 28, 2017 Order in Case No. U-17990, the Commission directed Consumers Energy to recalculate its AMI opt-out charges in its next general rate case following full deployment of AMI meters or in a contested case filed six months following full deployment, whichever occurred sooner. February 28, 2017 Order, page 158. In Case No. U-18322, the Commission modified that directive, at the Company's request, to eliminate the need for a stand-alone recalculation between rate cases. See March 29, 2018 Order, MPSC Case No. U-18322, page 128. This case is the first general rate case following full deployment of the Company's AMI meters. 4 TR 978.

Company witness Warriner presented testimony and exhibits in this case to support the Company's calculations updating the charges to reflect the current costs of providing this option for customers who do not desire to receive standard utility meter reading equipment. See 4 TR 977-988; Exhibit A-117 (LDW-4). Mr. Warriner explained that the non-transmitting meter charges were developed to recover the costs associated with developing and offering that option for customers. 4 TR 979. The costs associated with providing this option can be summarized as follows:

- Up-front Costs – include costs associated with testing required inventory levels of non-transmitting meters, costs associated with smart meter deployment work order exception processing and systems development costs to support the non-transmitting option, customer support costs, and appropriate meter exchange costs. 4 TR 979.
- The timing of when a customer declares their intent to opt-out of a smart meter installation will impact the up-front costs and associated charges. 4 TR 979. If a smart meter already exists on the customer’s premise, additional costs will be incurred by the Company to remove the smart meter and replace it with a non-communicating digital meter, resulting in a higher charge, 4 TR 984; and
- Ongoing Costs – Consumers Energy will incur monthly costs to enable and support the non-standard metering alternative. Monthly costs include meter reading activities and routine testing of meters in use at customer service locations. 4 TR 979.

Mr. Warriner testified that, during December 2017, there were 9,848 electric customers active in the Non-Transmitting Meter Provision, which is approximately 0.5% of all electric customers. 4 TR 978. Based on the Company’s actual customer participation number and updates of the Company’s costs, as reflected in Exhibit A-117 (LWD-4), Mr. Warriner recommends an increase in the up-front charges for AMI opt-out customers from \$69.39 to \$155.35 for customers who are newly participating in the program and do not already have a transmitting meter and from \$123.91 to \$223.52 for AMI opt-out customers who already have a transmitting meter. 4 TR 985; Exhibit A-117 (LDW-4), page 2. Again, based on the Company’s actual customer participation number and updates of the Company’s costs, Mr. Warriner recommends a decrease in the ongoing monthly charge for participation in the AMI opt-out program from \$9.72 per month to \$5.68 per month. 4 TR 988; Exhibit A-117 (LDW-4), page 2. No party to this case filed any testimony opposing Mr. Warriner’s updated calculations. The Commission should approve the updated AMI opt-out charges as proposed.

6. Residential DR Shadow Billing Or Trial Period

Staff witness Simpson testified in support of Consumers Energy having either a trial period or shadow billing to support DR. 6 TR 2571-2572. Mr. Miller responded that the Company agrees that shadow billing is an important component of educating and informing customers on how the different rate options will impact their electric bills. As such, the Company plans to replace its existing Internet Web Portal platform with one that includes the shadow billing capabilities. 5 TR 1832.

The Company is also investigating how to implement a three-month trial period. The Company anticipates needing to modify existing marketing materials such as web sites, brochures, terms and conditions, and call center scripts. Additional programming changes will need to be made to the automated enrollment forms used by Customer Service Representatives to allow for customers to de-enroll during this grace period. Although the Company believes that most of these costs can be mitigated by implementing the UPR provision described above, the Company will continue to monitor this activity and address the costs of customers de-enrolling from these programs on a case-by-case basis. 5 TR 1808.

7. Response To MEC/NRDC/SC/EC/MEIBC Proposal Regarding Reliability Performance Reporting On Customer Bills

Mr. Jester proposed that the Company report specific information about outages experienced during each billing month on the customer's bill and on the Company's website. 6 TR 2612. Ms. Brege testified regarding why the Commission should not adopt such a proposal.

“Q. Should the Commission adopt Witness Jester's recommendation for the Company to report specific information about outages experienced during each billing month on the customer's bill and on the Company's website?”

- “A. No. Communicating meters are providing the Company with more information than ever about customer outages; however, that data is imperfect. There are several reasons the Commission should not adopt this recommendation: (i) Extensive outages in a geographic area can result in meters failing to report an outage; (ii) a population of customers would be excluded – these customers include those who have either selected to retain a non-communicating meter or live in rural areas where the use of communicating meters has been more challenging; (iii) customer outage data is stored in multiple systems which are not billing compliant; and (iv) the Company does not have a plan or funding to implement Witness Jester’s recommendation.
- “Q. Witness Jester also recommends that data provided by the customer’s advanced meter should be considered a ‘report’ triggering automatic application of relevant bill credits on the customer’s next bill following a violation of the standards. Do you agree with this recommendation?
- “A. No. In addition to the four reasons listed in the previous answer, The Service Quality and Reliability Standards for Electric Distribution Systems clearly state that for Rules R 460.744 – *Penalty for failure to restore service after an interruption due to catastrophic conditions*, R 460.745 – *Penalty for failure to restore service during normal conditions* and R 460.746 – *Penalty for repetitive interruptions of the same circuit*, the utility ‘shall provide to any affected customer that notifies the utility of the interruption with a bill credit on the customer’s next bill.’ The Company does not feel that a meter generated report complies with the intent of the administrative rules. The Company believes a change to the administrative rules would be necessary in order to implement Mr. Jester’s proposal.” 5 TR 1633-1634.

As a result, Mr. Jester’s positions are unworkable and the Commission should reject them. Additionally, a rate case is not the appropriate avenue to recommend changes to administrative rules. Mr. Jester’s proposed changes would not solely apply to Consumers Energy, but would apply to all electric utilities as defined by R 460.562(e). The process for amending

administrative rules is governed by the Administrative Procedures Act, 1969 PA 306, MCL 24.201 to 24.328.

IX. CONCLUSION

For the reasons discussed in this Initial Brief and as set forth in the evidence presented by Consumers Energy Company, Consumers Energy Company requests that the Michigan Public Service Commission authorize an increase in electric rates sufficient to produce additional annual revenues in the amount of approximately \$44 million, and grant the other related relief as set forth in more detail in this Initial Brief and the record evidence.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Dated: November 9, 2018

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APPENDIX A

Consumers Energy Company

Comparison of the Revenue Requirement Calculation
for the Test Year Ended December 31, 2019
(\$000)

CECo Brief

Appendix A

Page 1 of 1

Line	Description	CECo Position as Filed ¹	Changes to CECo Position	Total Company CECo Brief Position	Jurisdictional CECo Brief Position	MPSC Staff Position As Filed ²	Difference (Col e less Col f)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Rate Base	\$ 10,715,021	\$ (32,281) ³	\$ 10,682,740	\$ 10,638,735 ³	\$ 10,577,184	\$ 61,551
2	Adjusted Net Operating Income	629,986	3,987 ⁴	633,973	635,487 ⁴	647,193	(11,707)
3	Overall Rate of Return	5.88%		5.93%	5.97%	6.12%	-0.15%
4	Required Rate of Return	6.33%		6.28%	6.28% ⁵	5.81%	0.47%
5	Income Required	678,581	(7,535)	671,046	668,282	614,295	53,987
6	Income Deficiency (Sufficiency)	48,595	(11,522)	37,073	32,795	(32,898)	65,694
7	Revenue Multiplier	1.3391	1.3391	1.3391	1.3391	1.3391	1.3391
8	Revenue Deficiency (Sufficiency)	\$ 65,073	\$ (15,429)	\$ 49,644	\$ 43,914	\$ (44,053)	\$ 87,969
9	Additional Staff Adjustment ⁶					(3,389)	3,389
10	Adjusted Revenue Deficiency (Sufficiency)	\$ 65,073	\$ (15,429)	\$ 49,644	\$ 43,914	\$ (47,442)	\$ 91,357

Footnotes¹ Exhibit: A-11 (HJM-39), Schedule A-1² Exhibit S-1, Schedule A1 (RF Nichols)³ Appendix B Page 1 of 2⁴ Appendix C Page 1 of 3⁵ Exhibit: A-147 (AJD-12)⁶ Direct testimony of Staff witness Fromm p.11

(Summer On-Peak Rate Marketing \$3.403M times Staff O&M jurisdictional factor)

APPENDIX B

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-20134

CECo Brief

Appendix B

Page 1 of 2

Consumers Energy Company

Comparison of Rate Base

for the Test Year Ended December 31, 2019

(\$000)

Line	Description	CECo Position as Filed ¹	Changes to CECo Position ²	Total Company CECo Brief Position	Jurisdictional CECo Brief Position	MPSC Staff Position As Filed ³	Difference (Col e less Col f)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Plant In Service	\$ 15,339,824	\$ (33,963)	\$ 15,305,861	\$ 15,244,990 ²	\$ 15,191,635	\$ 53,355
2	Plant Held for Future Use	5,277	-	5,277	5,233 ²	5,150	83
3	Construction Work In Progress	486,750	-	486,750	484,004 ²	473,719	10,285
4	Total Utility Plant	15,831,851	(33,963)	15,797,888	15,734,226	15,670,504	63,722
5	Depreciation Reserve	(5,862,598)	1,682	(5,860,916)	(5,837,490) ²	(5,835,069)	(2,421)
6	Net Utility Plant	9,969,253	(32,281)	9,936,972	9,896,736	9,835,435	61,301
7	Retainers & Customer Advances	(58,242)	-	(58,242)	(58,207)	(58,202)	(5)
8	Working Capital	804,011	-	804,011	800,206	799,951	255
9	Total Rate Base	\$ 10,715,021	\$ (32,281)	\$ 10,682,740	\$ 10,638,735	\$ 10,577,184	\$ 61,551

Footnotes

¹ Exhibit: A-12 (HJM-42), Schedule B-1

² Appendix B Page 2 of 2

³ Exhibit S-2, Schedule B1 (SAHarris)

Consumers Energy Company

Comparison of Rate Base
for the Test Year Ended December 31, 2019
(\$000)

Line	Description	Plant in Service	Plant Held For Future Use	CWIP	Depreciation Reserve	Net Utility Plant
	(a)	(b)	(c)	(d)	(e)	(f)
1	Projected Utility Plant - As Filed ¹	\$ 15,339,824	\$ 5,277	\$ 486,750	\$ (5,862,598)	\$ 9,969,253
	<u>Adjustments²</u>					
2	IT - ARP Storage Project	(2,036)	-		123	(1,913)
3	IT - Legal Archiving Tool	(500)	-	-	30	(470)
4	IT- Customer Experience Improvements	(800)			48	(752)
5	IT-ARP - WAM Project	(916)			110	(806)
6	HVD - New Business	(2,872)			88	(2,784)
7	Capital Contingency	(26,839)	-	-	1,283	(25,556)
8	Total Adjustments	(33,963)	-	-	1,682	(32,281)
9	Adjusted Projected Utility Plant	\$ 15,305,861	\$ 5,277	\$ 486,750	\$ (5,860,916)	\$ 9,936,972
10	Jurisdictional Factor ²	0.996023	0.991637	0.994358	0.996003	
11	Total Projected Utility Plant	\$ 15,244,990	\$ 5,233	\$ 484,004	\$ (5,837,490)	\$ 9,896,736

Footnotes

¹ Exhibit: A-12 (HJM-44), Schedule B-2

² Exhibit: A-165 (HJM-68)

APPENDIX C

Consumers Energy Company

Comparison of the Income Statement
for the Test Year Ended December 31, 2019
(\$000)

Line	Description	CECo Position as Filed ¹	Changes to CECo Position ²	Total Company CECo Brief Position	Jurisdictional CECo Brief Position ²	MPSC Staff Position As Filed ³	Difference (Col e less Col f)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
<u>Operating Revenue</u>							
1	Sales Revenue	\$ 4,270,880	\$ 2,546	\$ 4,273,426	\$ 4,273,426	\$ 4,250,406	\$ 23,020
2	Wholesale Revenues	25,491	-	25,491	-	25,345	(25,345)
3	Other Electric Revenue	52,233	-	52,233	52,194	52,169	25
4	Total Operating Revenue	4,348,604	2,546	4,351,150	4,325,620	4,327,686	(2,300)
<u>Operating Expenses</u>							
5	Fuel Cost	2,124,368	-	2,124,368	2,103,273	2,103,227	46
6	Other O&M Expense	596,376	(2,235)	594,141	591,683	581,608	10,075
7	Depreciation Expense	655,409	(2,192)	653,217	650,117	647,450	2,667
8	R&PP Tax	169,400	(379)	169,021	168,379	167,681	698
9	General Taxes	30,775	-	30,775	30,589	30,597	(8)
10	Local Income Tax	1,299	21	1,320	1,324	1,330	(6)
11	State Income Tax	38,881	705	39,586	39,685	40,500	(815)
12	Federal Income Tax ⁴	110,944	2,639	113,583	113,867	116,881	(3,014)
13	Total Operating Expenses	3,727,452	(1,441)	3,726,011	3,698,917	3,689,276	9,644
14	Total Net Operating Income	621,152	3,987	625,139	626,703	638,410	(11,945)
<u>Operating Income Adjustments</u>							
15	AFUDC	8,834	-	8,834	8,784	8,783	1
16	Income Tax Effect of Interest ⁴		Included in Line 12				
17	Interest Synchronization Adjustment ⁴		Included in Line 12				
18	Total Operating Income Adjustments	8,834	-	8,834	8,784	8,783	1
19	Total Adjusted Net Operating Income	\$ 629,986	\$ 3,987	\$ 633,973	\$ 635,487	\$ 647,193	\$ (11,944)

Footnotes¹ Exhibit: A-13 (HJM-49), Schedule C-1² Appendix C Page 2 of 3³ Exhibit: S-3, Schedule C1 (RF Nichols)

Staff exhibits incorrectly include wholesale revenue as jurisdictional.

Line 4 Total Operating revenue taken from Staff exhibits does not sum to total lines 1-3.

⁴ Income Tax Effect of Interest and Interest Synchronization are included in the calculation of Federal Income Tax. The separate calculations can be seen on Appendix D and Appendix E

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-20134

Consumers Energy Company

Comparison of the Income Statement
for the Test Year Ended December 31, 2019
(\$000)

CECo Brief

Appendix C

Page 2 of 3

Line	Description	Revenue				Expenses								NOI		
		Sales Revenue	Wholesale	Other	Total	Fuel Cost	O&M	Depreciation	R&PP Tax	General Taxes	CIT	MCIT	FIT	NOI	AFUDC	Adjusted NOI
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	Operating Income - As Filed ¹	\$ 4,270,880	\$ 25,491	\$ 52,233	\$ 4,348,604	\$ 2,124,368	\$ 596,376	\$ 655,409	\$ 169,400	\$ 30,775	\$ 1,299	\$ 38,881	\$ 110,944	\$ 621,152	\$ 8,834	\$ 629,986
	<u>Adjustments²</u>															
2	Revenue Adjustment	2,546	-	-	2,546	-	-			-	4	135	505	1,901	-	1,901
3	IT - ARP Storage Project							(245)	(23)		0	14	53	200	-	200
4	IT - Legal Archiving Tool							(60)	(6)		0	3	13	49	-	49
5	IT - Customer Experience Improvements							(96)	(9)		0	6	21	78	-	78
6	IT - ARP WAM Project							(110)	(10)		0	6	24	90	-	90
7	HVD New Business							(88)	(32)		0	6	24	90	-	90
8	Capital Contingency							(1,593)	(299)		3	100	376	1,413	-	1,413
9	Marketing Expense						(2,235)				4	118	444	1,669	-	1,669
10	Proforma Interest ³										9	315	1,178	(1,502)	-	(1,502)
11	Interest Synchronization ⁴										0	0	1	(2)	-	(2)
12	Total Adjustments	2,546	-	-	2,546	-	(2,235)	(2,192)	(379)	-	21	705	2,639	3,987	-	3,987
13	Adjusted Net Operating Income	\$ 4,273,426	\$ 25,491	\$ 52,233	\$ 4,351,150	\$ 2,124,368	\$ 594,141	\$ 653,217	\$ 169,022	\$ 30,775	\$ 1,320	\$ 39,586	\$ 113,583	\$ 625,139	\$ 8,834	\$ 633,973
14	Jurisdictional Factor ⁷	1.000000	-	0.999253		0.990070	0.995863	0.995255	0.996196	0.993962	1.002504	1.002504	1.002504		0.994358	
15	Jurisdictional Adjusted NOI	\$ 4,273,426	\$ -	\$ 52,194	\$ 4,325,620	\$ 2,103,273	\$ 591,683	\$ 650,117	\$ 168,379	\$ 30,589	\$ 1,324	\$ 39,685	\$ 113,867	\$ 626,703	\$ 8,784	\$ 635,487

Footnotes

¹ Exhibit: A-13 (HJM-62), Schedule C-14

² Exhibit: A-167 (HJM-70)

³ Appendix D

⁴ Appendix E

Line	Description	CECo Position as Filed ¹	Changes to CECo Position ²	Total Company	MPSC Staff	Difference (Col d less Col e)
				CECo Brief Position	Position As Filed ³	
	(a)	(b)	(c)	(d)	(e)	(g)
1	Electric Distribution	\$ 177,723		\$ 177,723	\$ 177,723	\$ -
2	Fossil & Hydro Generation	169,090		169,090	\$ 169,090	-
3	Operations Support	14,697		14,697	\$ 14,697	-
4	Information Technology	53,875		53,875	\$ 45,593	8,282
5	Fleet	182		182	\$ 182	-
6	Pension and Benefits	11,931		11,931	\$ 11,931	-
7	Corporate	52,562		52,562	\$ 52,562	-
8	Uncollectibles	18,594		18,594	\$ 18,594	-
9	Injuries & Damages	4,675		4,675	\$ 4,675	-
10	Demand Response	12,475		12,475	\$ 12,475	-
11	Customer Payment Programs	5,928		5,928	\$ 5,928	-
12	Customer Experience	58,321	(2,235)	56,086	\$ 57,553	(1,467)
13	Jobwork Expense	11,293		11,293	\$ 11,293	-
14	Incentive Compensation	5,029		5,029	\$ 1,740	3,289
15	Projected Other O&M Expense	\$ 596,376	\$ (2,235)	\$ 594,141	\$ 584,036	\$ 10,104
16	Jurisdictional Factor	0.994647	0.994647	0.995863	0.995843	
17	Jurisdictional Projected Other O&M Expense	\$ 593,184	\$ (2,223)	\$ 591,683	\$ 581,608	\$ 10,075

Footnotes

¹ Exhibit: A-13 (HJM-53), Schedule C-5

² Appendix C Page 2 of 3, Column (g)

³ Exhibit: S-3, Schedule C5 (Welke)

APPENDIX D

Consumers Energy Company

Tax Effect of Pro-Forma Interest Adjustment
for the Test Year Ended December 31, 2019
(\$000)

Line	Description	Amount	Source
	(a)	(b)	(c)
1	Rate Base	\$ 10,682,740	Appendix B Page 1 of 2
2	Weighted Cost of Debt ¹	<u>1.72%</u>	Exhibit: A-147 (AJD-12)
3	Allowable Interest Expense	183,888	Line 1 * Line 2
4	Projected Pro-Forma Interest Expense from Original Filing	<u>189,821</u>	Exhibit: A-13 (HJM-60), Schedule C-1
5	Increase/ (Decrease) in Allowable Interest Deduction	<u>(5,933)</u>	Line 3 - Line 4
6	Impact on Taxable Income	5,933	Line 5 * -1
7	CIT Rate	<u>0.16%</u>	
8	Impact on Local Income Tax	<u>9</u>	Line 6 * Line 7
9	Impact on State Taxable Income	5,924	Line 6 - Line 8
10	MCIT Rate	<u>5.310%</u>	
11	Impact on State Income Tax	<u>315</u>	Line 9 * Line 10
12	Impact of Federal Taxable Income	5,609	Line 9 - Line 11
13	FIT Rate	<u>21%</u>	
14	Impact on Federal Income Tax	<u>1,178</u>	Line 11 * Line 13
15	Impact on Net Operating Income	<u>\$ (1,502)</u>	(Line 8 + Line 11+ Line 14) * -1

Footnotes

¹ Excludes the Job Development Investment Tax Credit portion

APPENDIX E

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-20134

CECo Brief

Appendix E

Page 1 of 1

Consumers Energy Company

Tax Effect of Interest Synchronization Adjustment
for the Test Year Ended December 31, 2019

(\$000)

Line	Description	Amount	Source
(a)	(b)	(c)	
1	Rate Base	\$ 10,682,740	Appendix B Page 1 of 2
2	Debt Related JDITC ¹ Portion of the Capital Structure	<u>0.29%</u>	Exhibit: A-147 (AJD-12)
3	Portion of Rate Base Funded by JDITC	30,562	Line 1 * Line 2
4	Cost of Debt - JDITC Portion	<u>4.47%</u>	Exhibit: A-147 (AJD-12)
5	Allowable JDITC Interest Expense	1,366	Line 3 * Line 4
6	Projected JDITC Interest Expense from Original Filing	<u>1,373</u>	Exhibit: A-13 (HJM-61), Schedule C-13
7	Increase/ (Decrease) in Allowable JDITC Interest Expense	<u>(7)</u>	Line 5 - Line 6
8	Impact on Taxable Income	7	Line 7 * -1
9	CIT Rate	<u>0.160%</u>	
10	Impact on City Income Tax	<u>0</u>	Line 8 * Line 9
11	Impact on State Taxable Income	7	Line 8 - Line 10
12	MCIT Rate	<u>5.310%</u>	
13	Impact on State Income Tax	<u>0</u>	Line 11 * Line 12
14	Impact on Federal Taxable Income	6	Line 11 - Line 13
15	FIT Rate	<u>21%</u>	
16	Impact on Federal Income Tax	<u>1</u>	Line 14 * Line 15
17	Synchronization Adjustment to Net Operating Income	<u>\$ (2)</u>	(Line 10 + Line 13 + Line 16) * -1

Footnotes

¹ Job Development Investment Tax Credit

APPENDIX F

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-20134

CECo Brief

Appendix F

Page 1 of 2

Consumers Energy Company

Comparison of Capital Structure
for the Test Year Ended December 31, 2019
(\$000)

COMPANY BRIEF POSITION

Line	Description	CECo Position as Filed ¹	Changes to CECo Position	CECo Brief Position ²	% of Permanent Capital	% of Total Capital	Cost Rate ²	Weighted Cost	Weighted Cost of Debt	Pretax Weighted Cost
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Long Term Debt	\$ 6,692,915	(299)	\$ 6,692,616	47.24%	37.71%	4.47%	1.69%	1.69%	1.69%
2	Preferred Stock	37,315	-	37,315	0.26%	0.21%	4.50%	0.01%		0.01%
3	Common Equity	7,437,782	0	7,437,782	52.50%	41.90%	10.75%	4.50%		6.03%
4	Permanent Capital	14,168,012	(299)	14,167,713	100.00%					
5	Short Term Debt	153,772	228	154,000		0.87%	4.14%	0.04%	0.04%	0.04%
6	Customer Deposits	-	-	-		0.00%	0.00%	0.00%	0.00%	0.00%
7	Other Interest Bearing Accounts	-	-	-		0.00%	0.00%	0.00%	0.00%	0.00%
8	Deferred FIT	3,321,660	340	3,322,000		18.72%	0.00%	0.00%		0.00%
<u>Deferred JDITC/ITC</u>										
9	Long Term Debt	49,432	1,348	50,780		0.29%	4.47%	0.01%	0.01%	0.01%
10	Preferred Stock	332	(49)	283		0.00%	4.50%	0.00%		0.00%
11	Common Equity	57,145	(2,209)	54,936		0.31%	10.75%	0.03%		0.04%
12	Total Capitalization	\$ 17,750,353	\$ (640)	\$ 17,749,713		100.00%		6.28%	1.73%	7.82%

Footnotes

¹ Exhibit: A-14 (AJD-1), Schedule D-1

² Exhibit: A-147 (AJD-12)

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-20134

CECo Brief

Appendix F

Page 2 of 2

Consumers Energy Company

Comparison of Capital Structure
for the Test Year Ended December 31, 2019
(\$000)

COMPANY FILED POSITION

Line	Description	CECo Position as Filed ¹	% of Permanent Capital	% of Total Capital	Cost Rate ¹	Weighted Cost	Weighted Cost of Debt	Pre-Tax Weighted Cost
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Long Term Debt	\$ 6,692,915	47.24%	37.71%	4.60%	1.74%	1.74%	1.74%
2	Preferred Stock	37,315	0.26%	0.21%	4.50%	0.01%		0.01%
3	Common Equity	7,437,782	52.50%	41.90%	10.75%	4.50%		6.03%
4	Total Permanent Capital	14,168,012	100.00%					
5	Short Term Debt	153,772		0.87%	4.16%	0.04%	0.04%	0.04%
6	Customer Deposits	-		0.00%	0.00%	0.00%	0.00%	0.00%
7	Other Interest Bearing Accounts	-		0.00%	0.00%	0.00%	0.00%	0.00%
8	Deferred FIT	3,321,660		18.71%	0.00%	0.00%		0.00%
<u>JDITC/ITC</u>								
9	Long Term Debt	49,432		0.28%	4.60%	0.01%	0.01%	0.01%
10	Preferred Stock	332		0.00%	4.50%	0.00%		0.00%
11	Common Equity	57,145		0.32%	10.75%	0.03%		0.05%
12	Total JDITC/ITC	106,909		0.60%		0.05%		0.06%
13	Total Capital	\$17,750,353		100.00%		6.33%	1.78%	7.88%

Footnotes

¹ Exhibit A-14 (AJD-1), Schedule D-1

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-20134

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Melissa K. Harris, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on November 9, 2018, she served an electronic copy of the **Initial Brief of Consumers Energy Company** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein. She further states that she also served a hard copy of the same document to the Hon. Sharon L. Feldman at the address listed in Attachment 1 by depositing the same in the United States mail in the City of Jackson, Michigan, with first-class postage thereon fully paid.

Melissa K. Harris

Subscribed and sworn to before me this 9th day of November, 2018.

Samantha O'Rourke, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 10/30/21
Acting in the County of Jackson

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