January 5, 2026

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Hwy., 3rd Floor
Lansing, MI 48917

RE: Case No. U-21870 – 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. Felice:

Enclosed for electronic filing in the above captioned case please find the **Supplemental Reply Brief of Consumers Energy Company**. This is a paperless filing and is therefore being filed only in PDF. Also included is a Proof of Service showing service upon the parties in this case.

Sincerely,

Digitally signed by Gary A. Gensch, Jr.
Date: 2026.01.05 14:52:07 -05'00'

Gary A. Gensch Jr.
Phone: 517-788-0698
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cc: 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-21870

SUPPLEMENTAL REPLY BRIEF OF CONSUMERS ENERGY COMPANY

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SUPPLEMENTAL REPLY BRIEF OF CONSUMERS ENERGY COMPANY

I. INTRODUCTION AND OVERVIEW

The record evidence in this case supports final rate relief in the annual amount of approximately $422.8 million, plus an additional $24.3 million for the distribution deferral, a 10.25% ROE, and approval of other important requests detailed in Consumers Energy's Initial Brief. Many of the recommendations made by the other parties in this proceeding understate the level of revenue that is reasonable and constitutionally required for the test year and, if adopted, would result in unreasonable and unlawful rates. See *General Telephone Co v Pub Serv Comm*, 341 Mich 620, 631; 67 NW2d 882 (1954). Some parties argue that projected capital expenditures and O&M should be reduced by hundreds of millions of dollars based on the contention that funding should be limited to historical amounts (sometimes including inflation) or should be based on partial 2025 spending. See, for example, ABATE's Initial Brief, pages 15-16, 19-20, 25-28, 32-35, 60-69; MNSC's Initial Brief, pages 60-73; MPSC Staff's Initial Brief, pages 7-11, 14-19, 109-115. The methodologies used to develop these proposed cost reductions significantly understate the reasonable and appropriate cost amounts, and as a result, understate the Company's necessary revenue requirement. As discussed throughout the Company's Initial Brief, these unreasonable recommendations should be rejected.

II. RATE BASE

A. Net Utility Plant

1. Distribution Capital Expenditures

a. High Voltage Distribution

The Attorney General recommends that the Commission should direct the Company to "adopt an accounting policy to remove costs from rate base for cancelled projects." Attorney General's Initial Brief, page 31. The Attorney General's assertions would penalize the Company for taking the necessary actions to serve a requesting customer. A public utility "is bound from the very nature of its business to furnish such public service in such quantities as the public may require . . . ." *City of Saginaw v Consumers' Power Co*, 213 Mich 460, 481; 182 NW 146 (1921). See also Mich Admin Code R 460.106. In this case, acting under a signed contract, the Company started making investments on behalf of the customer. The Commission has regularly determined that having a signed contract with the customer results in the associated investments being reasonable and prudent. Furthermore, this project was presented in Case No. U-21585 and approved by the Commission. It is reasonable that the Company made investments to provide service to the connecting customer.

b. Low Voltage Distribution

(i.) LVD Lines Reliability

MNSC argues that Act 142 does not include any limitation on using securitization for capital costs, and that the Company's distinction between capital and O&M costs is "artificial." MNSC's Initial Brief, pages 142-143. The distinction is not "artificial" – O&M is normally not spread over several years, while capital expenditures are depreciated over time and allocated across the customers who benefit from the expenditures. See 3 TR 1086. And Act 142 does not authorize the MPSC to "require" the Company to use securitization, but rather makes it available "[u]pon

the application of an electric utility." See MCL 460.10i(1). The MPSC should reject MNSC's proposal to require the Company to securitize increased LVD pole replacement expenditures.

2. Facilities and Shared Services Capital Expenditures

a. Control/Dispatch Centers

Staff and the Attorney General recommend disallowances for the Control/Dispatch Center Consolidation project. In its Initial Brief, Staff argued that it would have expected the Company to spend bridge period amounts from Case No. U-21585 in 2024 while the case was ongoing since the Company did not yet know the outcome. Staff's Initial Brief, page 67. What the Company did know at the time, however, was the outcome of Case No. U-21389, and it was spending amounts authorized in that case (for the March 1, 2024 through February 29, 2025 test year in that case) while Case No. U-21585 was ongoing. The comparison is not as simple as Staff suggests since the Commission had not yet approved the Company's proposed spending in Case No. U-21585 (indeed, it was eventually rejected), and the Company was spending amounts authorized in Case No. U-21389. Ultimately, the amount the Company spent or did not spend in 2024 should not control whether the Company is allowed to recover its projected expenditures in this case. Rather, the sound basis for the Company's projection should control whether it is allowed to recover its expenses. See the Company's Initial Brief, pages 128-134.

3. IT and Security Capital Expenditures

a. ARP-FDAM and ARP-WAM

Concerning the ARP FDAM and WAM projects, Staff took issue with the Company's alleged failure to "provide more detailed information for its new projection method in rebuttal," and Staff said it had not been provided enough information to compare historical and projected new device purchases to historical and projected hires. Staff's Initial Brief, pages 52-54, 59-60. But Staff's own brief and referenced exhibits describe the extensive information the Company did

provide. *Id.* The Company identified the specific devices being replaced, see Exhibit A-22 (SHB-7), page 5; it provided the historical costs needed to calculate the four-year average Staff prefers for new purchases, see Exhibit A-183 (SHB-12); and it answered Staff's questions about the projects, including its questions about new hires. See Exhibit S-14.1, pages 5 and 6; Exhibit S-21.

b. Projects in the Investment Planning Phase

The Attorney General made one new argument concerning the Company's Integrated Energy Management Platform Optimization project claiming that because the Company would not be willing to risk an investment in the project if it were disallowed, then the Company must not be confident in the value of the project. Attorney General's Initial Brief, pages 106-107. The Company's response in Exhibit AG-75 indicates that the Company is confident that the project will lower costs for the Company and is crucial to the Company's provision of utility service. As Company witness Megan L. Jerore stated, "PCI provides software the Company uses to fulfill the [FERC] requirement of communicating unit availability to the [MISO] to efficiently buy and sell electricity in the wholesale market." 3 TR 1795. Ms. Jerore explained that the project will lower operational costs. 3 TR 1801. The project will provide cost savings as part of an expense that is necessary for the Company to meet a FERC requirement and therefore should be approved.

III. CAPITAL STRUCTURE AND RATE OF RETURN

A. Capital Structure Cost Rates

1. Return on Common Equity

a. Discounted Cash Flow Model

Staff's sole criticism of the Company's DCF analysis was to observe that two of the three growth rates used for one of the companies in Consumers Energy's proxy group (Dominion) were around 13.0% while the third was only 3.5%. Staff's Initial Brief, page 88. Staff claimed that

these growth rates "had the consequence of unduly boosting the Company's average and median ROE estimate." Staff's Initial Brief, page 88. That does not make sense for several reasons.

First, of the three estimates, the *low* estimate is the outlier – not the two *high* estimates. The growth estimates from *S&P Capital IQ* and *Zacks* are consistent with one another in both the Company's original DCF calculations (See Exhibit A-14 (AEB-1), Schedule D-5, pages 3-5) and its updated DCF calculations (See Exhibit A-206 (AEB-2), pages 2-4). If anything, the use of all three is artificially *reducing* the mean results of Ms. Bulkley's analyses compared to running the same analysis without the *Value Line* outlier. Second, while the *S&P Capital IQ* and *Zacks* growth rates of around 13% for Dominion remained relatively consistent when Ms. Bulkley updated them in her rebuttal, *Value Line*'s growth rate had nearly doubled by the time of Ms. Bulkley's update from 3.5% to 6.0%. See, e.g., Exhibit A-206 (AEB-2), page 2, column [5]. Clearly, in the time between the Company's direct testimony and its rebuttal testimony, even *Value Line* recognized that Dominion is expected to experience stronger growth than *Value Line* originally estimated.

Third, for each of her three DCF analyses, Ms. Bulkley performed a model run using the minimum growth rate, the maximum growth rate, and the mean growth rate from the three sources. See Exhibits A-14 (AEB-1), Schedule D-5, pages 3-5 and A-206 (AEB-2), pages 2-4. So, eliminating Dominion's three growth rate projections from the data set entirely could *increase* the results of Ms. Bulkley's minimum growth rate model run. For example, removing Dominion from Ms. Bulkley's original 180-Day Constant Growth DCF would increase the mean ROE result from 9.16% to 9.19% and the median ROE result from 9.79% to 9.81%.[1] Staff's claim that the inclusion

[1] To calculate the new mean, simply add all of the values in Exhibit A-14 (AEB-1), Schedule D-5, column [9], except the value for Dominion, and divide by 18 (the remaining number of proxy companies). To calculate the new median, simply arrange the values in Exhibit A-14 (AEB-1), Schedule D-5, column [9], except the value for Dominion, in order from lowest to highest and then select the value that is exactly in the middle. Since the new list would have an even number of values, the middle value is the average of the two values on either side of the middle point (i.e. the average of 9.79% for Southern Company and 9.83% for Ameren Corporation).

of Dominion had the effect of "unduly boosting" the Company's results is demonstrably false for at least some of the results.

Even for the maximum growth rate and the mean growth rate runs, removing the Dominion results from Ms. Bulkley's model does not significantly lower the results. For example, removing Dominion from Ms. Bulkley's original 180-Day Constant Growth DCF would change the mean ROE result from 10.47% to 10.20% and the median ROE result from 10.43% to 10.41% for the mean growth rate run.[2] For the maximum growth rate run of the same model, it would change the mean ROE result from 11.42% to 11.01% and the median ROE result from 11.01% to 10.97%.[3]

This issue highlights the importance of using objective criteria in the selection of the proxy group and not arbitrarily excluding any of the inputs for the proxy companies while running the models merely based on some subjective perception that the inputs appear to be outliers. Staff's criticism of the Company's DCF is entirely subjective and outcome-driven and must be rejected.

MNSC responds to Ms. Bulkley's observation that her constant growth DCF is more appropriate than MNSC's two-step DCF by arguing that "the constant growth DCF model is not a default" and that because it has fewer variables, the constant growth DCF is more sensitive to any bias that may influence one of the variables. MNSC's Initial Brief, page 49. Consumers Energy never claimed that the constant growth DCF was a "default" model. Instead, Company witness Bulkley clearly explained the constant growth DCF was the *appropriate* model for application in Consumers Energy's case because Consumers Energy is a "mature compan[y] with a stable history

[2] The process for calculating the new mean and median is the same as described above for the minimum growth rate run except that it uses the values from Exhibit A-14 (AEB-1), Schedule D-5, column [10].
[3] The process for calculating the new mean and median is the same as described above for the minimum growth rate run and the median growth rate run except that it uses the values from Exhibit A-14 (AEB-1), Schedule D-5, column [11].

of growth and stable future expectations." 4 TR 2842, 4 TR 2838. The two-step DCF is not an appropriate fit for the utility being analyzed here – Consumers Energy.

With respect to MNSC's claims regarding the sensitivity of the model to any single variable, that claim is also not valid because it ignores that Ms. Bulkley used multiple data sources for her DCF inputs specifically to reduce or eliminate any potential bias in her variables. She calculated three different dividend yields (4 TR 2740) and used EPS growth forecasts from three different sources (4 TR 2742) for each of her proxy companies. The EPS growth forecasts that she used were from consensus forecasts (4 TR 2837), which means that even those were gathered from multiple analysts' evaluation of growth. So, she used fewer variables but made sure to draw those variables from numerous sources to ensure that there was no single-source bias.

Second, MNSC argued that it is "reasonable to presume" that the studies Consumers Energy cited are probably flawed because "less productive utilities were acquired or replaced by more productive utilities." MNSC's Initial Brief, page 49. MNSC offered no evidence to substantiate that there are any meaningful numbers of failed utilities disappearing from the market. An article from the Energy Law Journal in 2001 identified four "major electric utilities . . . that filed for protection under Chapter 11 of the Bankruptcy Code since the end of the Depression era." Mabey & Malone, *Chapter 11 Reorganization of Utility Companies*, 22 (No.2) Energy L J 277, 283 (2001). The article further identified four "smaller electric utilities which have filed for bankruptcy in recent years." *Id*. at 283, n 20. Electric utility failure does not appear to be a common occurrence. The betas for utility companies suggest that they are lower risk than the overall market, indicating that there is less volatility in this industry than the market as a whole. But, even MNSC's claims of a "survivorship bias" in the data were true, it does not support MNSC's case. When investors choose to invest their money in a utility, it is not reasonable to

assume that they benchmark their expectations for growth against failed companies. Intentionally including data from failed utilities would underestimate investor expectations and improperly hamper the capital attraction objective of the ratemaking ROE. There *should* be a survivorship bias in the analysis.

Third, MNSC claims that Ms. Bulkley disagrees with MNSC's DCF calculation using DPS growth but failed to "address [MNSC witness] Bandyk's testimony regarding the advantages of using DPS growth rates." MNSC's Initial Brief, page 49. The only "advantage" that MNSC witness Matthew Bandyk claimed for using DPS was to cite the opinion of the Massachusetts DPU, which claimed that "firms tend to keep their dividend growth stable over time, as opposed to EPS growth rates, which may vary based on firm-specific events and economic conditions." 6 TR 3969. Company witness Bulkley did not directly address Mr. Bandyk's claim in rebuttal because she already addressed it in her direct testimony and she provided an example as to how companies manage dividends in response to Mr. Walters. Ms. Bulkley stated that "due to the economic effects of COVID-19, more than 40 companies in the S&P 500 temporarily suspended their dividends. Counter to Mr. Walters's assumption, a company's management will alter dividend policy to respond to changes in earnings and therefore dividend growth will not always reflect earnings growth." 4 TR 2758. In her direct testimony, Ms. Bulkley explained that "over the long run, dividend growth can only be sustained by earnings growth . . . ." 4 TR 2741. She further explained that "changes in a company's dividend payments are based on management decisions related to cash management and other factors," which means that "dividend growth rates are less likely than earnings growth rates to accurately reflect investor perceptions of a company's growth prospects." 4 TR 2741. This information directly contradicts the Massachusetts DPU's claim – adopted by MNSC's witness – that "firms tend to keep their dividend growth stable over

time" because it explains a variety of reasons businesses may choose to vary their dividend payments even while trying to steadily grow their earnings. Thus, Ms. Bulkley testified that "projected EPS growth is the appropriate measure of a company's long-term growth." 4 TR 2741.

b. Capital Asset Pricing Model

MNSC claims that Mr. Bandyk's risk-free rate based on 10-year U.S. Treasury bonds is superior to Ms. Bulkley's risk-free rate based on 30-year U.S. Treasury bonds. MNSC's Initial Brief, page 50. MNSC argues that the 10-year U.S. Treasury "more closely matches the duration the rates set in this case will be in effect, while remaining sufficiently long-term to mitigate volatility." *Id*. However, the risk-free rate doesn't need to match the duration of times that rates will be in effect. It needs to match the duration of the underlying investment. 4 TR 2848. Utility investments are long-term and the risk associated with those investments is a long-term risk. If the investors' money will be tied up in utility assets that depreciate over 30 years or more, then they will compare the potential return on that investment to other alternatives of a similar duration, like 30-year U.S. Treasury bonds. An investor does not expect to make a 30-year investment to earn a return that is commensurate with a 10-year investment.

Next, MNSC tries to respond to Ms. Bulkley's rebuttal testimony demonstrating that MNSC witness Bandyk's market risk premia were flawed. Ms. Bulkley demonstrated that Mr. Bandyk's equity risk premia were below the historical average equity risk premium even though his risk-free rates were also below the historical average risk-free rates. 4 TR 2857-2858. Because of the well-documented inverse relationship between the risk-free rate and the market risk premium, when one goes up the other should go down and vice versa. When both move in the same direction (as they did in Mr. Bandyk's analysis) then there is self-evidently something wrong in the analysis. First, MNSC claims that historical estimates are "meaningless" because they are "extremely sensitive to the historical time period selected . . . ." MNSC's Initial Brief, page 51.

Second, MNSC claims that the historical estimates are "meaningless" – once again – because of survivorship bias. MNSC's Initial Brief, page 51. Consumers Energy has already addressed MNSC's claims regarding survivorship bias above. With respect to MNSC's claims about the historical time period chosen, the Company agrees with the principle that MNSC articulates here, but MNSC fails to recognize that the objective way to address that problem is to use the entire historical data set, which is exactly what Ms. Bulkley did. 4 TR 2854-2855. Because Ms. Bulkley used all of the available data to make the comparison, there was no opportunity for her to introduce any analyst bias in her calculation.

Next, MNSC attempts to respond to Ms. Bulkley's observation that Mr. Bandyk's market risk premia are inconsistent with his own DCF results. MNSC's only response to Ms. Bulkley's analysis is to claim that she is making "an apples-to-oranges comparison by comparing market risk premia calculated by Dr. Damodaran using a DCF analysis for the S&P 500 to a DCF analysis for Consumers performed by Mr. Bandyk." MNSC's Initial Brief, pages 51-52. MNSC argues that "[d]ifferent results from different analyses performed by different analysts do not invalidate the results of either analysis." MNSC's Initial Brief, page 52. First, it is not truthful to claim that these were different analyses. Dr. Damodaran's values were the result of DCF analyses (see 6 TR 3958-3960) and Ms. Bulkley was comparing those results to the results of Mr. Bandyk's DCF analyses. Mr. Bandyk even admitted that Dr. Damodoran was essentially using "the same discounted cash flow model Ms. Bulkley and I use to estimate the cost of equity for a single company and applies it to value the expected return of a broad market index, the S&P 500." 6 TR 3958 (emphasis added). It was the same analysis except that Dr. Damodaran's DCF was for the whole S&P 500, with a beta of 1.00, and Mr. Bandyk's was for the proxy group, with a beta of 0.92 (*Value Line*) or 0.68 (*Bloomberg*). 4 TR 2860. So, Mr. Bandyk's results should have been

lower and Dr. Damodaran's results should have been higher, but they weren't. Second, even if MNSC were correct that these were different analyses (which they were not), different results from different analysis performed by different analysts *do* invalidate the results of one or both analyses *if* both analyses claim a different result for the same market at the same time. Thus, there is an inescapable problem with the inputs Mr. Bandyk used for his CAPM analysis and, hence, a problem with his CAPM results. Based on his DCF results, his market risk premia for his CAPM should have been significantly higher and should have produced higher CAPM results. That doesn't even take into account that the Company has shown that Mr. Bandyk's DCF results were also too low. Obviously, the higher the DCF results, the higher his CAPM risk premia should have been and the higher his CAPM results.

Finally, MNSC claims in its Initial Brief that Ms. Bulkley "offers no support" for her observation that Blume adjusted betas in the CAPM "better reflect the true beta of the utility sector inclusive of interest rate risk." MNSC's Initial Brief, page 52. That is incorrect. Ms. Bulkley testified that "the utility sector is not only correlated to the broader market, but is also sensitive to changes in interest rates." 4 TR 2861. She explained that raw betas, such as those used by Mr. Bandyk in his CAPM analyses, do not factor interest rate risk into their calculation. 4 TR 2744, 2861.

MNSC also claims that Ms. Bulkley failed to address the reasons that Mr. Bandyk offered to explain why the use of adjusted betas is supposedly inappropriate for regulated utilities. Mr. Bandyk claimed that "[r]ate regulation protects investor-owned utilities like Consumers Energy from the risks of rising expenses, commodity price risk, and competitive risks, and they enjoy natural monopolies that mitigate market risks associated with the customer base." 6 TR 3964. He claimed that "commodity prices tend to be passed through directly to customers, and

utilities can request a rate increase if sales decline." 6 TR 3964. This is an overly simplistic view of how rate regulation works in practice. Public utilities, like Consumers Energy, still face risks associated with rising expenses, commodity price risk, and competitive risks. Although utilities certainly try to address those risks in rate cases, it is not a foregone conclusion that the results of rate cases will result in rates that fully address those concerns. Utilities do not typically obtain the full amount of the rate relief they seek and are forced, like any other business, to find efficiencies and other mechanisms to manage uncovered risk. Furthermore, Consumers Energy frequently experiences disallowances in its Power Supply Cost Recovery cases, such that it seldom gets full recovery of its commodity costs for electricity. Certainly a utility can "request" a rate increase if sales decline, but unregulated businesses can increase their prices without a lengthy regulatory proceeding if their sales decline or costs are rising. Consumers Energy understands the need for and the proper role of rate regulation in this industry, but it is not the risk-free panacea that MNSC claims. To the extent that rate regulation does make utilities slightly less risky than other businesses in the marketplace, that is reflected in adjusted betas that are below the market beta of 1.00. As Ms. Bulkley pointed out in her rebuttal testimony, both Staff witness Kirk D. Megginson and Attorney General witness Coppola use Blume adjusted betas in their CAPM analyses. 4 TR 2862. It remains the standard for CAPM analyses notwithstanding Mr. Bandyk's novel claims that it is inappropriate. The Commission should disregard MNSC's argument.

2. <u>Short-Term Debt Rate</u>

In its Initial Brief, Staff attempts to respond to Company witness Marc R. Bleckman's rebuttal testimony, which explained the reasons why Staff's proposal to remove the costs associated with the ScotiaBank Revolver in the Company's next electric rate case should be rejected. Among other problems with Staff's proposal (see Consumers Energy's Initial Brief, pages 296-299), Mr. Bleckman explained that Staff's proposal to simply move the existing letters

of credit that are backed by the ScotiaBank Revolver to be backed by the Company's JPMorgan Revolver is not a viable option because (i) the JPMorgan Revolver has a limit of $100 million for letters of credit and (ii) the letters of credit associated with the ScotiaBank Revolver ($58 million) exceed the remaining limit of $50 million on the JPMorgan Revolver. 3 TR 892.

Staff's Initial Brief responds by claiming that this information is "novel and unsubstantiated" and that this is the "first time the Company has brought up or even mentioned a so-called letter of credit limitation with the JPMorgan facility." Staff's Initial Brief, pages 85-86. However, there was no reason for Mr. Bleckman to mention that particular term of the Company's JPMorgan Revolver prior to Staff's unworkable recommendation to use it in that way. It only became relevant when Staff raised the issue.

Staff also claims in its Initial Brief that it "seems implausible" that the terms of the Company's ScotiaBank Revolver "has more letter of credit capacity" than the terms of the JPMorgan Revolver. Staff's Initial Brief, page 86. The underlying assumption behind this supposedly "implausible" situation was that the ScotiaBank Revolver has a higher letter of credit capacity than the JPMorgan Revolver, but that is not true and there is no support for Staff's claim in the record. The record only indicated that letter of credit capacity under the JPMorgan Revolver, which was $100 million. 3 TR 892. The record also indicates that the Company had $58 million of letters of credit committed under the ScotiaBank Revolver, but did not say what the letter of credit capacity on that revolver was. See 3 TR 892. In fact, the letter of credit capacity under the ScotiaBank Revolver was only $75 million at the time the record closed in this case, so it was *lower* – not higher – than the letter of credit capacity for the JPMorgan Revolver. It is also important that Mr. Bleckman specified that the $58 million of outstanding letters of credit supported by the ScotiaBank Revolver "pertain to MISO." 3 TR 892. That is significant because

MISO has a requirement related to letters of credit in its tariff that requires same-day funding under certain circumstances. See MISO, FERC Electric Tariff, Attachment L, Exhibit II (FERC Docket No. ER24-340-000). That requirement creates additional risk for the funding banks that support the letters of credit. As a result, many banks – including JPMorgan – generally refuse to issue MISO-related letters of credit. ScotiaBank is one that will.

Finally, Staff claims that Mr. Bleckman's Exhibit A-39 (MRB-20), which shows that the Company's short-term credit facilities are in line with its peer group companies' short-term credit facilities, should be "view[ed] . . . with caution." Staff's Initial Brief, page 87. Staff encourages the Commission to ignore all of the peer utilities shown on Exhibit A-39 (MRB-20) and focus solely on DTE's short-term credit facilities. That does not make sense. DTE is tied for the third lowest ratio of revolver capacity to PP&E among the 15 peer utilities shown on Exhibit A-39 (MRB-20). Put another way, 11 of the 15 peer utilities have a higher revolver-to-PP&E ratio than DTE. There is no valid reason to disregard every other peer utility and rely solely on DTE to evaluate the reasonableness of Consumers Energy's revolver-to-PP&E ratio. Consumers Energy's revolver-to-PP&E ratio is slightly below the average of 5.4%. If Consumers Energy were included in the list, 9 of the other 15 companies would have a higher ratio than Consumers Energy and only 5 would have a lower ratio. The Company's portfolio of short-term credit facilities is reasonably sized. Staff's recommendation relative to the Company's ScotiaBank Revolver should be rejected.

IV. ADJUSTED NET OPERATING INCOME

A. Other O&M Expense

1. Line Clearing O&M Expense

Staff takes issue with some aspects of the Company's line clearing plan. For example, Staff wants more aggressive line clearing beyond the more aggressive practices the Company proposed, and it argues the line clearing expenses the Company requested should be enough to

cover both the move "towards a 5-year line clearing cycle *and* removal of 100% of overhang in the first zone." Staff's Initial Brief, page 140 (emphasis added). The Company is not necessarily opposed to Staff's proposal *if* it is first allowed to evaluate the costs and benefits. See 3 TR 2241. If the Commission approves the Company's more targeted proposal to remove 5,500 miles of canopy – both within and outside the first zone – the Company will have a better data set from which to evaluate the costs and benefits of additional canopy removal.

Staff also characterized the Company's plan as a "proposal to clear 10% or 5,500 miles of three phase overhead primary tree overhang removal in everything outside of the first zone." Staff's Initial Brief, page 140. The Company's plan is not limited to miles outside of the first zone and does not cover all miles outside of the first zone. The Company is proposing canopy removal on targeted three-phase lines considering the impact that outages would have on customers served downstream and whether the conductor is within the path of a substation-to-substation connection that enables switching if needed. 3 TR 2206. Approving the Company's plan as proposed will deliver the most benefits to customers for the cost.

Concerning future line clearing spending, Staff recommended that "the Company spend the entire amount of line clearing expenses approved in each rate case they file and complete all line miles that are being proposed to be trimmed each year." Staff's Initial Brief, page 142. The Company is not opposed to a requirement that it spend its approved line clearing expenses, but the Company should continue to have operational flexibility to accelerate or postpone plans to clear some line miles. Staff disagreed with the Company that it spent over what was authorized in the Case No. U-21389 rate case for the test year. Staff's Initial Brief, page 141. As for calendar year spending, the Company answered Staff's questions to the best of its ability and, even after reading

Staff's Initial Brief, still does not understand what information Staff believed was withheld.[4] Finally, Staff wants the Company to perform an analysis of a four-year line clearing cycle in its next case that includes several specific elements. Staff's Initial Brief, page 144. Although the Company has already analyzed a four-year cycle, it is certainly open to further analysis in the future. The next rate case is likely too soon though. The Company should first be allowed to make progress toward its proposed five-year cycle, which is itself an immense undertaking.

In its Initial Brief, page 138, MNSC argues that using historical amounts to set the baseline amount for the LVD line clearing ramp up deferral is supported by the Commission's preference for historical test years adjusted for known and measurable changes as stated in Case No. U-13898. But the Commission's "preference" stated in Case No. U-13898 was before the passage of 2008 PA 286. In its November 2, 2009 Order in Case No. U-15645, page 6, the Commission recognized that with the passage of 2008 PA 286 and the use of a projected test year, "the dynamics of determining costs requires a certain degree of forward projections," and that "[w]hat is gained by dealing with data that is 'known and measurable' can be lost in forcing a utility to operate with outdated numbers." The baseline amounts proposed by MNSC and the Attorney General are "outdated" and should be rejected because they disregard the fundamental shift in operations to transition to a five-year LVD line clearing cycle. 3 TR 1083-1084.

2. Generation O&M Expense – Emergent Reliability Expense

Staff attempted to respond to Mr. Blumenstock's rebuttal explaining that past Emergent Reliability Expense is not included in future expense forecasts in its Initial Brief. Staff's response

[4]Staff points out that the Company spent $5,876,252 less on LVD line clearing in 2024 than it projected in Case No. U-21585. The Company nonetheless spent everything it committed to spending in the U-21585 test year (keeping in mind that the Case No. U-21585 test year did not include several months of 2024 and included two months of 2025), so no funding was reallocated. This is why, when Staff asked about the $5,876,252, the Company responded that it "did not redeploy these funds." Exhibit S-18, page 1.

was essentially to claim that none of Mr. Blumenstock's testimony on this issue is true. See Staff's Initial Brief, page 118. Staff simply says that it "disagrees" with the Company. Staff's Initial Brief, page 118. But Mr. Blumenstock's testimony was factual testimony. The Company **does not** forecast its test year O&M for generation by taking historical amounts and inflating them.

Staff calculates that the Company's total generation O&M for the test year is higher than its total generation O&M in 2024 (after excluding J.H. Campbell O&M). Staff's Initial Brief, page 119. Even though Staff's calculation of the difference does not correspond to the amount of the Emergent Reliability expense (either historical or test year), Staff concludes that the historical Emergent Reliability expense amount must be in the test year in addition to the $2.849 million projected amount merely because the total amount of O&M went up. That inference doesn't pass any type of logic test. Say, for example, that a car owner budgeted $1,000 for a known need to get new tires in 2024 and $100 for any other unforeseen car maintenance costs (total: $1,100). But, during 2024, the owner needed a new battery for $150 (going slightly over budget). Then in 2026, the car owner budgeted $5,000 for a known need to replace the transmission and again $100 for any other unforeseen car maintenance costs that might occur in 2026 (total: $5,100). Staff's logic is that because the total cost in 2026 is higher than the cost in 2024, then the 2026 budget *must* include both the $100 of emergent car cost in 2026 and the $150 emergent car costs from 2024. As this illustration shows, that conclusion is not justified.

Finally, Staff prepares a table to compare (i) the 2024 historical Emergent Reliability expense by plant to (ii)(a) an inflated version of those historical amounts and (ii)(b) the test year expenses projected for each plant. Staff's Initial Brief, page 120. Again, Staff concludes that because the total amount for those plants collectively in the test year is higher than the total amount for those plants collectively in 2024, the historical Emergent Reliability expense amount must be

in the test year in addition to the $2.849 million projected amount. This is the same faulty logic discussed above, but applied to a smaller subset of the Company's generation O&M costs. If the Company's test year O&M were simply an inflated version of the Company's 2024 O&M amount, then columns (c) and (d) of Staff's table should perfectly match. They don't. Even if Staff assumed (again, contrary to Mr. Blumenstock's factual testimony) that the Company may be inflating the 2024 O&M, but then adding some additional O&M on top to derive its test year amount, then none of the values in column (d) should be less than its corresponding value in column (c) and certainly not lower than its corresponding value in column (b). That reasoning is also disproven by Staff's own table. Both the Jackson and D.E. Karn test year amounts are *less than* the inflated version of the 2024 historical actual amounts for those plants. The amount for the Jackson plant is even lower than the 2024 historical amount.

The Company's Emergent Reliability expense forecast for the test year is very conservative compared to its recent actual expense amounts and there is no double-inclusion of any Emergent Reliability expense amount from the historical year in the projected test year. The Commission should reject Staff's unreasonable disallowance.

3. Customer Experience and Operations O&M Expense

In its Initial Brief at pages 115 through 117, the UCC argues that the funds for the Company's DCO and Analytics and Outreach work should be disallowed, contending that the Company has not shown how these expenses benefit customers. The Company supported the reasonableness of these costs. The Company's Analytics and Outreach group incorporates customer feedback and data into the Company's operations. This contributes to improving customer experience. 3 TR 967.41. This group allows the Company to use its resources more efficiently, target communications to precise customer segments, and select programs that are most likely to provide customer value. Some of the work undertaken by this group includes all MPSC

reporting, customer Estimated Time of Restoration, data quality, and data automation. 3 TR 367.42. Analytics and Outreach efforts allow the Company to more efficiently utilize its resources, target communications to precise customer segments, and select, develop, and implement programs that are most likely to provide customer value.

The DCO team is responsible for the operation and continuous improvement of the Company's customer-facing digital applications, including its website and mobile application. The team leads the design, development, and launch of the Company's technologies, as well as ensuring that the technologies are responsive to customer needs and requested changes. 3 TR 967.10. The DCO team keeps the website and mobile app running, accessible for and responsive to Consumers Energy customers. 3 TR 967.11. The DCO team is critical to the success of the Company's objective to digitize transactions to better serve customers on the website, which is a more cost-effective means of serving customers than other channels. The costs of these groups are reasonable and should be recovered in rates.

4. Corporate Services O&M Expense

a. Corporate Memberships

UCC argues "the Company has failed to provide sufficient evidence to prove that it has not included any expenses associated with advocacy, lobbying, or activities that undermine the interests of ratepayers in its request for recovery." UCC's Initial Brief, page 132. UCC's claims are false and misleading. UCC makes a false claim that "[t]he Company did not convert the specific figures in Workpaper WP-PDD-18 to the test year to account for inflation, which Company Witness Foster said in cross examination was the reason for differences between Workpaper figures and requested recovery amounts." See UCC's Initial Brief, pages 123-124. This is clearly not true as Mr. Foster explains "Consumers Energy uses … inflation rates to project

Corporate Services O&M." 5 TR 3357. In translating the amounts from the workpaper to the O&M exhibit, Mr. Foster explained he adjusted for inflation. Further, UCC notes "[i]t was not until the Company provided its rebuttal testimony that it pointed intervenors to a spreadsheet containing historic membership dues calculation methodology and a breakdown of historic dues expenses, Workpaper 'WP-PDD-18.'" UCC's Initial Brief, page 123. This workpaper was part of the Company's initial filing, and the Company should not be penalized for UCC's failure to fully review the filing the Company made.

UCC next claims the corporate membership dues should be disallowed because "Consumers has failed to provide sufficient, concrete benefits to ratepayers which would justify recovering costs from ratepayers." UCC's Initial Brief, page 125. But in the very next sentence to justify this standard, UCC articulates a different standard based on the Commission ordering DTE to provide a detailed description of how corporate memberships in organizations "specifically impact/benefit customers". UCC's Initial Brief, page 126. This directive was specifically issued to DTE and cannot be interpreted as a requirement for Consumers Energy. Further, the Commission approved DTE's corporate membership expense in that referenced case.

UCC's final argument is that dues paid to organizations that engage in advocacy that allegedly undermines customers' interests violates customers' constitutional rights. It is well established that the Commission has no inherent or common law powers. *Union Carbide Corp. v Public Service Commission*, 431 Mich 135, 146; 428 NW2d 322 (1988). While the Commission cannot issue a declaratory ruling as to the constitutional issues discussed by UCC, UCC's recommendation related to this issue was for the Commission to "establish a concrete standard barring recovery where trade associations dedicate significant resources to political advocacy".

UCC's Initial Brief, page 143. But recovery related to political advocacy is already excluded from this expense. See 5 TR 3372-3374. The remaining amount has been clearly supported.

5. Information Technology O&M Expense

In its Initial Brief, the Company refuted the Attorney General's proposed capital disallowance for the Company S/4HANA project in the "Accounting Request" and "IT and Security Capital Expenditure" sections. Company's Initial Brief, pages 150-153, 458. The same arguments the Company made in response to the Attorney General's proposed capital expenditure adjustments apply equally to her proposed $15,178,000 O&M expense adjustment. See Attorney General's Initial Brief - CONFIDENTIAL, pages 104-105.

V. COST OF SERVICE, RATE DESIGN, AND TARIFF ISSUES

A. Cost of Service

1. EAC Report & Distribution Cost Allocation

MNSC's Initial Brief incorrectly claims that Consumers Energy "proposes to change the methodology by which the Cost of Service Study (COSS) allocates the costs of distribution assets" in this case because the Company is using a new EAC report in place of its old T&D report to update the cost categories used in the COSS. MNSC's Initial Brief, page 74. MNSC makes this claim despite the fact that Company witness Emily A. Davis testified that the EAC report "did not change the categorization of LVD energized lines, line equipment or batteries from the Company's last rate case nor did it fundamentally change how distribution costs are allocated." 4 TR 2670. In this case, the Company is still breaking out costs by FERC account and voltage level and using a Class Peak allocator to allocate costs to customers attached to and downstream of that equipment. 4 TR 2652-2656. The methodology has not changed. The only difference is that the Company now has more granular detail about the costs in those FERC accounts, which allows the Company to apply the Class Peak allocators more precisely.

MNSC argues, "Whereas the Company used to allocate the cost of distribution assets based on class peak at the highest voltage connected to the asset, the new method allocates costs based on the highest voltage level downstream of the asset. The upstream or high side voltage connected to the asset would no longer bear any cost responsibility for the asset." MNSC's Initial Brief, page 75. MNSC then cites Ms. Davis's rebuttal as if it supports this claim, but Ms. Davis was clear during cross examination that she did not agree with MNSC's characterization of how the allocators worked before and after the development of the EAC. 4 TR 2689. During cross exam, MNSC asked Ms. Davis to confirm that the new category of "HVD (Voltage 1) Bulk Power (Shared V2, 3, 4)," which is allocated solely to Voltage 2, 3, and 4 customers would have been part of the "HVD (Voltage 1)" category in Case No. U-21585, which was allocated to Voltage 1, 2, 3, and 4 customers in that case. 4 TR 2690. Ms. Davis affirmed that was correct. *Id*. But, the reason that Ms. Davis disagreed with MNSC's characterization is that the new category "HVD (Voltage 1) (V1 Only)" in this case *also* was included in the "HVD (Voltage 1)" category in Case No. U-21585. Which means that in Case No. U-21585, Voltage 2, 3, and 4 customers were paying for costs that are now solely allocated to Voltage 1 customers. When there is a cost category that groups both types of assets (i.e. (i) assets that serve only Voltage 1 customers and (ii) assets that serve only Voltage 2, 3, and 4 customers) into a single category with no way to differentiate them (as was the case in Case No. U-21585 and other previous cases), then the only way to allocate those costs is to allocate whole collective batch of costs to all four voltage groups, knowing that each voltage group is theoretically paying for some portion of the other group's assets and vice versa. The EAC simply disentangled the assets for both groups so that neither group is paying for the other group's assets and each group is now only paying for its own assets. The EAC shifts costs *in both directions* so that no group is paying for costs it did not cause.

Under the Company's proposal in this case, Rate GPD Voltage 1 customers would actually experience a significant *increase* in the distribution component of their rates as shown on Exhibit A-16 (LMC-3), Schedule F-3.0, page 11. That exhibit shows that Rate GPD Voltage 1's distribution costs would increase from $2.571 million to $6.312 million, an increase of 145%. There is no reason to believe that the EAC shifts costs away from Rate GPD Voltage 1 to other customers. The Commission should reject MNSC's arguments regarding distribution cost allocation as it relates to the EAC report.

2. <u>Advanced Metering Infrastructure Meter Cost Allocation</u>

On pages 89-93 of its Initial Brief, MNSC claims that federal and state law "requires AMI costs to be allocated according to program benefits" and concludes that "the Company is currently departing from cost-causation principles." No such legal requirement exists.

MNSC's claim is principally based on a shallow reading of federal case law pertaining to FERC's application of the cost-causation principle under federal law. The first problem with MNSC's claim is, of course, that the MPSC is not required to conform Michigan ratemaking to FERC or federal court decisions about how to apply the cost-causation principle in federal cases. Federal perspectives on the cost-causation principle are, at most, persuasive materials that the Commission is free to adopt or not as the Commission sees fit for state ratemaking purposes.

Even if the Commission were to agree that it is appropriate to adopt a similar application of the cost-causation principle followed by FERC, however, MNSC's characterization of that principle is not accurate. Federal courts have held that the cost-causation principle "traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them." *K N Energy, Inc v FERC*, 968 F2d 1295, 1300; 297 US App DC 13 (1992). In *Midwest ISO Transmission Owners v FERC*, 373 F3d 1361, 1368; 362 US App DC 314 (2004), the U.S. Court of Appeals for the D.C. Circuit, in reviewing whether FERC's allocation of

Independent System Operator costs to certain transmission customers was lawful, held that "we evaluate compliance with this unremarkable [cost-causation] principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." But, the mere use of the word "benefits" does not, as MNSC suggests, prove that the federal courts broadly meant to abandon the "cost-causation"-centered focus of the cost-causation principle and transform it into a "benefits"-centered principle.

Furthermore, the U.S. Court of Appeals only reviews FERC cost allocation decisions like this to ensure that the cost allocation mechanism is not "arbitrary and capricious." *Id*. at 1369. Therefore, when the U.S. Court of Appeals adopted its methodology of comparing costs assessed against the burdens imposed or benefits drawn by a party in *Midwest ISO Transmission Owners*, the Court was not establishing a prescriptive standard for how FERC *must* allocate costs; it was only adopting a deferential standard for guiding its own post hoc review of FERC's cost allocation decisions. Federal courts do not require FERC to engage in a "benefits"-centered analysis, but are clear that "FERC need not use a 'particular formula' or 'allocate costs with exacting precision.'" *Paragould Light & Water Comm v FERC*, 144 F4th 287, 292 (DC Cir, 2025).

MNSC cites *Paragould* for the proposition that "[t]he cost-causation principle requires that customers receive benefits 'roughly commensurate' to the costs they pay for a given transmission facility." *Id*. See MNSC's Initial Brief, page 90. The Paragould Court went on to state: "FERC may not force customers to pay for a facility if they do not receive any benefits from it." *Id*. In other words, if FERC allocates costs to a customer, federal courts will regard that allocation as "arbitrary and capricious" when the customer does not experience sufficient benefits from the cost. But that observation does not support the converse proposition that FERC *must* assign costs to a customer if there is *any conceivable* benefit. The Courts' doctrine only establishes criteria for

when FERC may *not* assign costs to particular customers, not when it is *required to* assign costs to particular customers. Federal case law does not support MNSC's claim that federal law requires AMI costs to be allocated according to program benefits.

In Order 1000 (136 FERC 61051 (2011)), FERC established its own principles for the showing that a transmission owner must make in compliance filings in order to support the appropriateness of its proposed cost allocation formula, which the U.S. Court of Appeals has endorsed. See *Old Dominion Elec Coop v FERC*, 898 F3d 1254, 1256; 438 US App DC 89 (2018). The first principle in FERC's requirements was that costs "must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits." 136 FERC 61051, ¶ 622. While this language might initially appear to support the conclusion that FERC follows a "benefits"-centered view of cost allocation, FERC indicated this was consistent with its view of determining cost-causation principles, which asks "whether a proposal fairly assigns costs among those who cause the costs to be incurred and those who otherwise benefit from them." *Id*. at ¶ 623. Again, in a "cost-causation"-centered philosophy, the cost-causer is expected to incur benefits as a result of the costs that it has caused the utility to incur, so use of the word "benefits" does not imply that FERC's cost-causation philosophy is "benefits"-centered rather than "cost-causation" centered. Based on FERC's clarification, it is clear that FERC's focal point is still cost causation. However, FERC acknowledged concerns from commenters in the proceeding that "the definition of benefits could be interpreted too broadly or too narrowly." *Id*. at ¶ 625. FERC elected not to attempt to further define "benefits" for purposes of its Order 1000; however, FERC stated: "We expect that concerns regarding overly narrow or broad interpretation of benefits will be addressed in the first instance during the process of public utility transmission providers consulting with their stakeholders.

If such interpretations should emerge, we can more effectively ensure that the term is not given too narrow or broad a meaning by considering a specific proposal and a record than by attempting to anticipate and rule on all possibilities before the fact." *Id*. FERC further specified that "any benefit used by public utility transmission providers in a regional cost allocation method or methods must be an identifiable benefit . . . ." *Id*. Therefore, it is evident that FERC was aware of the potential of an interested party to too broadly assert the concept of "benefits" in an effort to justify cost allocation where it is not really appropriate, and FERC clearly did not intend to embrace every conceivable form of "benefits" as adequate to support a cost allocation proposal.

The fifth principle in FERC's requirements from Order 1000 was that "the cost allocation method and data requirements for determining benefits and identifying beneficiaries . . . must be transparent with adequate documentation to allow a stakeholder to determine how they were applied . . . ." *Id*. at P 668. FERC recognized that "identifying which types of benefits are relevant for cost allocation purposes, which beneficiaries are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial." *Id*. at 670. FERC concluded that the method "must balance being pragmatic and implementable with being accurate and unbiased." *Id*. at 671. Accordingly, FERC stated that public utility transmission providers, in preparing their cost allocation proposal, were "free to consider suggestions . . . that only direct costs and benefits should be considered in economic studies." *Id*. Again, FERC was aware of the potential of an interested party to too broadly assert the concept of "benefits" in an effort to justify cost allocation where it is not appropriate, and FERC once again demonstrated that it did not intend to embrace every conceivable form of "benefits" as adequate to support a cost allocation proposal.

Even if the Commission were persuaded to adopt principles like FERC's (which it is not required to do), FERC's principles fall far short of "requiring" AMI costs to be allocated

"according to program benefits" as MNSC perceives them. The "benefits" that MNSC claims customers receive as a result of the AMI investments are clearly "indirect" benefits and are susceptible to the challenge that MNSC is interpreting the term "benefits" too broadly. Although MNSC asks the Commission to significantly change the longstanding methodology for allocating AMI costs, MNSC offers nothing to show that its proposed cost allocation balances "being pragmatic and implementable with being accurate and unbiased." Consumers Energy submits that the type of benefits that MNSC focuses on are not the types of benefits that are typically treated as "relevant for cost allocation purposes." As Company witness Davis testified, "the installation and investment in a meter is driven by the need to connect and serve a customer." 4 TR 2672. A customer's receipt of a meter enables the customer to begin receiving electric service and ensures that the electric service the customer receives will be accurately measured and timely used for billing purposes. Those are the types of direct benefits that are relevant for determining which customers "caused" the utility to incur the cost of an AMI meter.

MNSC then falsely claims that the Commission "adheres to these cost causation principles, requiring utility costs to be broadly allocated according to the benefits accrued to each customer class." MNSC's Initial Brief, page 91. MNSC cites only one Commission case as supposed support for that proposition, Case No. U-10554. However, Case No. U-10554 does not support MNSC's conclusion either. It is correct, as MNSC claims, that the Commission found in Case No. U-10554 that a Demand Side Management program would "benefit all customers." See MPSC Case No. U-10554, June 19, 1995 Order, page 13. But, that does not mean that the Commission intended to adopt a broad "benefits"-centered cost allocation philosophy. The Commission made it clear that its view on cost allocation for the Demand Side Management program was grounded on the Commission's recognition that the program "provides an alternative to construction of new

power plants," which was "the basis for the design of rates associated with those programs." *Id*. In other words, the Commission viewed the cost-causation for Demand Side Management programs the same way it views cost causation for new power plants – all customers cause those costs, so all customers should be allocated a portion of the costs. In fact, the Commission explicitly stated in Case No. U-10554 that "the costs of [Demand Side Management] are not allocated based upon the benefits that customers receive." *Id*. at 14. The actual basis of the Commission's allocation of the Demand Side Management costs was clearly on the theory that the costs are caused in the same way that power plant costs are caused. In another case, where the Commission addressed cost allocation for power plants, the Commission has been clear that it "continues to view cost allocation in accordance with cost causation principles." MPSC Case No. U-16794, June 7, 2012 Order, page 107.

For all the reasons discussed above and in the Company's Initial Brief, there is no valid justification for MNSC's proposed changes to the allocation of AMI costs. The Commission should reject MNSC's proposal.

VI. OTHER ISSUES

A. Distribution Investment Recovery Mechanism

For the first time in this case, UCC requests quarterly reporting on project completion rates, spending versus budget, and equity outcomes in the IRM going forward. UCC's Initial Brief, page 104. The Commission should reject this additional reporting requirement because the separate IRM reconciliation already addresses these matters. See 3 TR 1619-1620.

B. Distribution System Planning and Analysis

UCC argues that the Company has not complied with the Case No. U-21389 requirement to make GIS reliability data publicly available. UCC's Initial Brief, pages 95-96. UCC is

incorrect. As directed in Case No. U-21389, the Company met with Staff multiple times and developed the existing publicly accessible map with Staff's input. 3 TR 1621.

C. Customer Assistance Programs

At pages 20 through 41 of its Initial Brief, UCC alleges that the Company's current payment assistance programs are not adequate and argues for the adoption of a Percentage of Income Payment Plan program. For the reasons previously stated in its Initial Brief, Consumers Energy disagrees with this recommendation. Additionally, the Company supports Staff's position that "the Commission should continue its plan to modify energy assistance programs through the MPSC Case No. U-20757 case docket and Staff's energy affordability report and align its decisions on energy assistance across all relevant open dockets." See Staff's Initial Brief, page 192.

UCC argues that the Company should be required to present an affordability analysis "incorporating the Commission's definition of energy affordability" in rate cases. UCC's Initial Brief, pages 46, 56, and 62. First, the Company does consider customer affordability and addressed it in this filing, including describing and improving on a range of customer assistance options. See 3 TR 967.25-967.41, 1821. Consistent with MCL 460.11(2), the Company included funding for customer assistance options in rates. See 3 TR 944; Exhibit A-16 (LMC-3), Schedule F-3.0. Second, the Commission is not bound to any particular formula in setting rates, but rather considers "all relevant factors in exercising its broad discretion to determine a just and reasonable rate." *ABATE v Public Service Commission*, 208 Mich App 248, 259 (1994). And third, the MPSC should not require the Company to conduct the affordability analysis that UCC requests because the details of the analysis are unclear and the Company does not have all of the information needed to perform the requested analysis. See 3 TR 967.71-967.72, 1848.

D. Virtual Power Plants

GLREA argues that the Commission has the authority to require utilities to undertake VPPs. GLREA's Initial Brief, page 6. But GLREA does not identify a single Michigan statute that provides the MPSC such authority. All of the MPSC's authority must be found in statutory enactments, and doubtful powers do not exist. *Consumers Power Co v Public Service Commission*, 189 Mich App 151, 176 (1991). And the MPSC's authority to regulate rates does not include the power to make management decisions. *Union Carbide*, 431 Mich App 148. The MPSC has no legal authority to require the Company to implement a near-term VPP program in this case.

E. Customer Outage Credit

UCC proposes changes to the customer outage credit. UCC's Initial Brief, page 67. The Commission should reject this new proposal because customer outage credits are governed by MPSC rules (see R 460.744, 460.745, and 460.746), and there is no evidence that the Company has failed to comply with these rules. See also Case No. U-20629, September 11, 2025 Order.

VII. CONCLUSION

Consumers Energy Company requests that the Michigan Public Service Commission grant the relief requested at pages 460-461 of the Company's Initial Brief.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Dated: January 5, 2026

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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 the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Crystal L. Chacon, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on January 5, 2026, she served an electronic copy of the **Supplemental Reply Brief of Consumers Energy Company** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Crystal L. Chacon

Crystal L. Chacon

Subscribed and sworn to before me this 5th day of January 2026.

Melissa K. Harris

Melissa K. Harris, Notary Public
State of Michigan, County of Jackson
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