December 3, 2024

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

RE: Case No. U-21585 – 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 **Initial Brief of Consumers Energy Company.** This is a paperless filing and is therefore being filed only in a PDF format. A Proof of Service showing electronic service upon the parties is included.

Sincerely,

Digitally signed by Gary A. Gensch, Jr.
Date: 2024.12.03 16:15:53 -05'00'

Gary A. Gensch Jr.
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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-21585

INITIAL BRIEF OF CONSUMERS ENERGY COMPANY

December 3, 2024

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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-21585

INITIAL BRIEF OF CONSUMERS ENERGY COMPANY

I. INTRODUCTION AND OVERVIEW

Consumers Energy Company ("Consumers Energy" or the "Company") filed its Application in this case on May 31, 2024, seeking an increase in its electric rates sufficient to produce additional revenues in the approximate annual amount of $303 million based on a projected 12-month test year ending February 28, 2026, plus an additional $22 million for the distribution deferral. The Company subsequently adjusted its case in response to issues raised by the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") and Intervenors, and lowered its request to approximately $255.4 million annually. See Appendix A, line 10, column (e).

The parties to this proceeding are: Staff; the Michigan Attorney General ("Attorney General"); Energy Michigan, Inc. ("Energy Michigan"); the Michigan Energy Innovation Business Council, the Institute for Energy Innovation, and Advanced Energy United (collectively, "MEIU"); the Foundry Association; the Michigan Cable Telecommunications Association ("MCTA"); the Michigan Environmental Council ("MEC"), Natural Resources Defense Council ("NRDC"), Sierra Club, and the Citizens Utility Board of Michigan ("CUB") (collectively,

"MNSC"); the Michigan Electric Transmission Company, LLC ("METC"); the Michigan Municipal Association for Utility Issues ("MAUI"); the Association of Businesses Advocating Tariff Equity ("ABATE"); the Kroger Company ("Kroger"); Walmart, Inc. ("Walmart"); the Environmental Law and Policy Center ("ELPC"), Vote Solar, Union of Concerned Scientists, and Ecology Center (collectively, the "Clean Energy Organizations" or "CEO"); Hemlock Semiconductor Operations LLC ("HSC"); the Great Lakes Renewable Energy Association ("GLREA"); Urban Core Collective ("UCC"); and the Michigan State Utility Workers Council ("MSUWC").

Evidentiary hearings began on October 30, 2024 and concluded on November 4, 2024. Pursuant to the schedule established by Administrative Law Judge Sally L. Wallace ("ALJ"), Initial Briefs are due December 3, 2024, and Reply Briefs are due December 17, 2024. The Proposal for Decision target date is January 27, 2025.

The record evidence in this case supports final rate relief in the annual amount of approximately $255.4 million, including an additional $22 million for the distribution deferral, a 10.25% Return on Equity ("ROE"), and approval of other important requests detailed herein. Except as otherwise noted, the Commission should reject other parties' arguments to the contrary, and should issue an order granting the Company's requested relief in full. 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.

A vital component of the Company's requested rate relief is the investments necessary to transform the electric distribution system and accelerate improvements to the reliability and resiliency of the grid. Over the course of recent years, the Commission has, in no uncertain terms, made clear its expectation that Consumers Energy must improve performance in electric

distribution reliability and resiliency. In numerous orders, statements from the bench, press releases, and Legislative testimony, the Commission and its members have consistently and forcefully voiced their demand for improved reliability. Consumers Energy agrees with this important stand for customers.

The Commission has directly instructed the Company to take new and different action to achieve the desired improvements in reliability. In its September 8, 2022 Order in Case No. U-20147 (page 67), the Commission concluded that the Company's 2021 Electric Distribution Infrastructure Investment Plan ("EDIIP") – the basis for the Company's three electric rate cases preceding the instant case – was "insufficient to address reliability concerns." The Commission forcefully stated, "**Put bluntly, Michigan's distribution reliability is inadequate, and current plans for improvements are insufficient**." *Id.* (emphasis added).

A month later, in ordering a third-party audit of the Company's distribution system and performance, the Commission again called for improvements in reliability, stating:

> "[Customers] have a right to expect the utilities to anticipate extreme weather events, to provide a hardened grid that can withstand extreme weather, and to be prepared to restore power expediently when the grid fails; and the Commission is committed to implementing improvements in these areas. The Commission has conducted numerous investigations into weather-related events and service quality issues since at least 1991 . . . Weather-related events are not uncommon in Michigan, and the August 2021 storms cannot be dismissed as unique or unlikely to ever reoccur. In fact, the pace of climate change dictates that such events will likely only become more frequent and planning must be responsive to this reality. As part of responding to the effects of climate change on the incidence of extreme weather, the Commission has ramped up efforts to examine the reliability and resilience of the distribution system and the impacts of aging infrastructure, and to implement the changes that are required to reduce the potential for death and injury and the possibility of larger and lengthier power outages.
>
> ***

> "These efforts have produced some effective measures, particularly in the area of vegetation management. However, the Commission is concerned that not enough progress has been made in the last year to harden the 4.8 kV system or to increase measures that ensure the safety of the public and utility workers who encounter the electrical distribution system. . . .**Taking the same action yet again and expecting a different result is not working in the best interests of Michigan's customers. Additional measures are necessary**."
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> ***
>
> "The Commission recognizes that significant work is ongoing in the distribution planning process, and further recognizes that changes cannot occur overnight." [Case No. U-21305, Order dated October 5, 2022, page 11 (emphasis added).]

The Commission has also indicated an intent to penalize Consumers Energy if it does not meet the Commission's increasingly high reliability standards, through mechanisms such as the performance based ratemaking process pending in Case No. U-21400.

The third-party distribution audit of Consumers Energy's distribution system and performance ordered in Case No. U-20147 occurred over the 2023-2024 time period, and the MPSC Staff filed the auditor's comprehensive report on September 23, 2024 in Case No. U-21305. In commenting on the audit, the Chair of the Commission stated "The audit underscores that now is the time for [Consumers Energy] to focus more on strategic investments to prevent outages rather than reacting to them." See MPSC Press Release dated September 23, 2024, available at https://www.michigan.gov/mpsc/commission/news-releases/2024/09/23/mpsc-releases-utility-audit-results-of-states-two-largest-electric-utilities.

Consumers Energy agrees that it must improve its electric distribution reliability. The Company has made significant progress on this goal. While the Company's performance has historically been in the fourth quartile of electric utilities, the Company is making steady progress to achieving a goal of second quartile performance. The Company is progressing on its plan to achieve second quartile performance by 2029. The Company's System Average Interruption

Duration Index ("SAIDI") performance has improved significantly over the past decade, and last year marked the second year of a two-year SAIDI trend in the right direction. Although there is more work to do, the recent strides represent promising progress and show that the Company's investments and plan for improvement are paying off for customers.

Consumers Energy agrees that more work remains to be done to provide customers the electric reliability they deserve. The Company needs to have a grid that is going to be reliable—now—but also resilient for the future. To that end, in 2023 the Company developed and filed with the Commission its Reliability Roadmap in Case No. U-20147, which is the research-based plan to achieve the desired improvements in performance. The Reliability Roadmap is included in this case as Exhibit A-111 (MPK-19). The Reliability Roadmap is directly responsive to the Commission's pointed direction that reliability must improve, and that doing the things the way they have been done in the past will not produce the desired results.

In this case, Consumers Energy has also directly responded to the Commission's calls for improved distribution reliability performance. The Company's case includes the plan to begin to implement the Reliability Roadmap. As previously noted by the Commission, the desired improvements cannot occur overnight; the Company agrees and has presented the initial steps needed to continue its improvements in distribution performance.

While the Reliability Roadmap cannot be implemented overnight, it is imperative that it begin in earnest. For that to occur, it is imperative that the investments and expenses associated with the implementation be approved. This case is where the rubber hits the road—the Company cannot continue its reliability improvements unless it has the cost recovery necessary to do so, as proposed by the Company.

It would not be appropriate for the Commission to approve the proposed reliability programs but to discount recovery of the costs needed to perform the approved work. This would be unrealistic, unreasonable, and unfair. The Commission should reject proposals which amount to implicit acceptance of the work proposed, but at dramatically reduced costs from those supported by the Company's witnesses. It is unrealistic to base projected test year costs for needed reliability investments upon historical averages. These types of proposed disallowances of distribution project costs (made by Staff and the Attorney General), if adopted, would amount to providing the Company historically based funding for reliability when the Commission itself, as well as the third-party auditor, have recognized that investments and expenses on the distribution system must increase in order for reliability to improve as desired. The time is now to approve the Company's proposed distribution reliability cost recovery to empower the Company to execute on the plans to improve reliability performance.

It would also not be appropriate to slow the pace of the Company's proposed reliability investments and work. The cost of waiting or slowing the pace is evident – the Company is on pace to reach second quartile reliability performance by 2029, and prolonging the pace of the work that must be done will delay these benefits. The time to act is now.

II. TEST YEAR

References in the Record: Myers, 4 TR 426-434; Aponte, 2 TR 392, Exhibits A-11 (JCA-27) through A-13 (JCA-51); Dauphinais, 5 TR 3286-3296; Deupree, 5 TR 2909-2914

A. Overview

Each rate case requires selection of a test year. A test year is used to establish representative levels of revenues, expenses, rate base, and capital structure for use in setting rates. 2008 Public Act ("PA") 286 ("Act 286") provides for the use of projected test years in setting utility rates. MCL 460.6a(1). Consistent with this statutory authority, Consumers Energy

used a projected 12-month test year ending February 28, 2026 for determining final rate relief in this case. 4 TR 392; Exhibits A-11 (JCA-27) through A-13 (JCA-51).

B. ABATE's and the Attorney General's Positions Should be Rejected

ABATE witness James R. Dauphinais proposed that, rather than approving the Company's use of a projected test year in this case, the Commission should instead use the historical test year revenue deficiency amount of $69.8 million, adjusted downward to reflect ABATE's position on ROE and capital structure. 5 TR 3292-3293. To support his position, Mr. Dauphinais argued that projected bridge period and test year expenses are not "known and measurable" changes to Consumers Energy's historical test year, and that Consumers Energy had test year revenues above the authorized return in five out of eight of the most recent general rate cases. 5 TR 3289, 3292. Similarly, Attorney General witness Michael W. Deupree expresses his concern with the use of projected test years and provided his own criteria for evaluating whether the investment will be "used and useful" during the test year. 5 TR 2909-2911.

The Commission should reject both Mr. Dauphinais' and Mr. Deupree's positions, as they are inconsistent with the Company's right to use a projected test year for determining rates. Act 286 states, in part, that "[a] utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges." MCL 460.6a(1). In Case No. U-15645, one of the first rate cases conducted after the enactment of Act 286, the Commission recognized that MCL 460.6a(1) provided a shift in the regulatory ratemaking paradigm - changing from the use of historical, known, and measurable costs, with known and measurable adjustments, to forward-looking, projected costs. The Commission interpreted MCL 460.6a(1) to provide utilities with "explicit authorization to rely on projections of its future costs and revenues" and recognized that the "debate regarding the proper test year was decided by the Legislature and the Commission finds the use of a future test year to be the proper measure of projected costs and

revenues." November 2, 2009 Order in Case No. U-15645, page 8. As the Commission recognized, MCL 460.6a(1) expressly provides a utility the right to have its rates based on a projected test year.

The Commission has since consistently rejected arguments that would require that rates be based on a historical test year. See, *e.g.*, MPSC Case No. U-21389, March 1, 2024 Order ("U-21389 Order"), page 6; MPSC Case No. U-20963, December 22, 2021 Order ("U-20963 Order"), page 9; MPSC Case No. U-20697, December 17, 2020 Order, page 7; and MPSC Case No. U-20322, September 26, 2019 Order ("U-20322 Order"), page 10. As the Commission stated in the U-20963 Order, "pursuant to the clear language of the statute, the utility's proposed test year may be in the future, and the 12 months must be consecutive." U-20963 Order, page 9. The Commission noted that "the statute contains no limitation on the future consecutive 12-month period, no requirement to use an historical test year, and no information or limitation regarding the relationship between the date of the application and the test year." *Id*. (quoting MPSC Case No. U-20561, May 8, 2020 Order, page 11).

The Attorney General's and ABATE's positions are contrary to MCL 460.6a(1) and the Commission's repeated explanation of the statutory requirement. They also ignore the significant evidence presented by the Company's witnesses sponsoring and providing supporting detail on the various projects and programs that make up the projected costs in this case. The Commission should review the Company's projected test year spending based on the support provided by the Company witnesses for every increase and decrease, and each new item, rather than having a blanket disallowance that would only reflect the historical test year revenue deficiency based on, for example, Mr. Dauphinais' disagreement with the use of a projected test year. Neither the

Attorney General nor ABATE can abrogate Consumers Energy's statutory right to use projected costs and revenues for a future test year through testimony.

Use of the projected test year is the most accurate way to set rates because it provides the calculation of rates necessary during the period for which the rates will be in effect. A projected test year also provides the opportunity for Intervenors to review and comment on the Company's planned spending prior to when it occurs. 4 TR 428. The Company is incentivized to hold spending at the levels approved in rates because once rates are established, the Company will need to manage the business within those rates, including managing risks (such as weather) that are outside the Company's control. *Id*. Setting rates based on historical spending only allows for review of spending after it has occurred, which can lead to the negative consequences of Company write-offs for disallowances after the dollars are spent and an inefficient use of finite dollars available to invest in the system. 4 TR 430. Customers are better served by allowing parties to understand and raise concerns with how dollars will be spent before the spending occurs. *Id*.

Mr. Dauphinais contends that if the use of projected years was working properly, "about half the time Consumers' historical test years would have a revenue deficiency and about half the time Consumers' historic test years would have a revenue sufficiency such that over time on average Consumers is just receiving enough revenues to earn its authorized rate of return." 5 TR 3290. Setting aside whether Mr. Dauhpinais' reasoning is valid (it is not), the data he provided in fact show that "about half the time" over the last eight rate cases there was a revenue deficiency in the historical test year (three of eight rate cases), with a total revenue deficiency over that time of $126,188,000. See 5 TR 3287, Table JRD-3. In addition, Company witness Heidi J. Myers demonstrated that in the Company's three most recent rate cases that did not conclude with a settlement agreement and that have a completed test year, Consumers Energy spent the capital

amounts that were approved by the Commission. 4 TR 429. The Company did not underspend the amounts included in rates in these cases.

In purported support for his application of a "used and useful" standard, Attorney General witness Deupree cited the Commission's U-20963 Order, page 103, wherein the Commission disallowed expenditures for the J.H. Campbell ("Campbell") Power Plant Unit 3 Pulse Jet Fabric Filter Bag. 5 TR 2913; U-20963 Order, pages 101-102. However, the U-20963 Order recognized that (i) the Commission had previously allowed recovery of costs prior to being "used and useful," and (ii) that the Commission expected additional supporting evidence in support of the investment given the proposed accelerated retirement of Campbell Unit 3. U-20963 Order, page 103. Thus, the Commission disallowed these expenditures because it was not convinced that they were needed, not based on an application of the "used and useful" standard. 4 TR 433. The Commission certainly did not adopt a blanket "used and useful" standard.

Indeed, the Commission's ruling in the same order on the Hardy Dam Auxiliary Spillway projected capital expenditure refutes Mr. Deupree's position. See U-20963 Order, pages 116-119. ABATE had proposed a disallowance of the project costs because the project construction was not expected to begin until after the test year. The Commission rejected ABATE's argument, stating that the Company "demonstrated by the evidence on the record that it will incur costs in the test year" and that the Commission did "not find it reasonable to withhold cost recovery until the project is complete and used and useful when the company has presented persuasive support that the projected spending is reasonable and prudent." U-20963 Order, pages 118-119.

To accept the "used and useful" standard, or the outright rejection of the projected test year, as a means to disallow projects without deeper consideration, would disregard the evidence

provided by Company witnesses in support of the reasonableness and prudence of investments. 4 TR 434. It would also be contrary to Michigan law. Rather than applying these blanket disallowances of projected costs, the Commission should continue to evaluate each proposed program and project on its own individual merits to determine whether the projected spending is reasonable and prudent.

III. RATE BASE

A. Net Utility Plant

1. Distribution Capital Expenditures

a. Overview

References in the Record: Kelly, 5 TR 840-940, 1002-1004, 1025-1034, 1040-1048; 1058-1121, Exhibits A-12 (MPK-1), Schedule B-5.6, A-94 (MPK-2) through A-103 (MPK-11), A-111 (MPK-19); Kurdziel, 5 TR 2003-2134, Exhibits A-123 (KMK-1) through A-126 (KMK-4), A-247 (KMK-5) through A-249 (KMK-7); McPhail, 5 TR 2202-2298, Exhibits A-132 (SAM-1) through A-139 (SAM-8); Lynd, 4 TR 500-767, Exhibits A-127 (DAL-1) through A-129 (DAL-3), A-250 (DAL-4), A-250 (DAL-5)

In September 2023, Consumers Energy filed its most recent update to the five-year EDIIP in Case No. U-20147, which the Company also described throughout testimony and in this Initial Brief as the "Reliability Roadmap." 5 TR 844. The Reliability Roadmap is provided as Exhibit A-111 (MPK-19). The Reliability Roadmap details the Company's plans for an electric distribution system that is (1) safe, (2) reliable and resilient, (3) clean and equitable, and (4) competitive. 5 TR 845. To meet these objectives, the Reliability Roadmap establishes the investments needed over the next several years to reliability through activities such as increased line clearing, asset hardening, rehabilitation, and automation. *Id*.

The Company's proposals outlined in the Reliability Roadmap are directly responsive to the Commission's and other stakeholders' concerns with the reliability of the Company's distribution system. Unusually severe storms and widespread outages in August 2021 led to the

Commission initiating a thorough review of reliability in Michigan in Case No. U-21122. 5 TR 853. As part of the process, several technical conferences were held and multiple stakeholders offered input. The Commission ultimately concluded that existing distribution investment plans were insufficient to ensure reliability and directed the Company to file a new distribution investment plan, which led to the filing of the Reliability Roadmap. 5 TR 854. CUB also expressed concern with reliability in Michigan in the 2023 edition of its Utility Performance Report, and the Attorney General called for improved reliability and creation of a website that seeks to collect power outage data. 5 TR 863. Rapid improvements in SAIDI have also been proposed to avoid financial penalties in Case No. U-21400. The significant improvement in reliability demanded by the Commission and stakeholders requires the investments identified in the Reliability Roadmap. 5 TR 864.

The Reliability Roadmap identifies two major risk factors to the distribution system: (1) increasingly severe weather; and (2) technological innovation driving increased demand on the grid, primarily distributed solar generation, Electric Vehicles ("EVs"), and electrification of heating. 5 TR 855. The Company's scenario modeling projects an increase of 10-15% in severe weather-related outages by the early 2030s compared with 2020 levels. 5 TR 857. This modeling illustrates that the most critical and immediate priority for the Company to focus distribution investments is the reliability and resiliency of the system in the face of these increasing storms. *Id*. As a result of the analysis undertaken in the Reliability Roadmap, the Company was able to better identify the types of investments that are needed, where they should occur, and what levels are needed to sufficiently harden the system and improve reliability even as weather worsens. 5 TR 858. With weather getting worse, recent historical levels of distribution investment will not deliver the reliability improvements that the Commission and our customers expect. 5 TR 860.

In order to put the learnings from the Reliability Roadmap into action, the Company is proposing to increase investment in four key categories of work:

- **Forestry Line Clearing** - maintaining clearance between vegetation and energized lines and mitigating vegetation that hinders accessibility to electric assets for line workers;

- **Hardening** - repairing and replacing equipment on High Voltage Distribution ("HVD") and Low Voltage Distribution ("LVD") lines and substations, addressing infrastructure at risk from severe weather impacts and infrastructure assessed to be in poor health, and performing proactive resiliency work such as converting overhead lines to underground;

- **Inspections/Preventative Maintenance** - providing ground and aerial inspections on both the LVD and HVD systems and fixing identified failures, particularly through the Demand Failures and Rehabilitation programs; and

- **Digital Automation** - providing technological solutions to increase efficiency of distribution planning, service restoration, and line clearing, enhancing employee and public safety and reducing the cost of work. 5 TR 859.

The Reliability Roadmap lays out a multiple year distribution strategy and investment plan, and this rate case applies the initial years of that investment to specific investment programs, sub-programs, investment categories, and projects. 5 TR 869. Key safety investments include voltage conversions, subsurface transformer replacements, open-wire secondary conversions, and the Wildfire Risk Mitigation Program. 5 TR 871. Reliability and resiliency improvements will be gained through investments in the LVD Reliability sub-programs, HVD Reliability sub-programs, Grid Modernization, and line clearing. 5 TR 877. The Company's goal of a clean and equitable grid is supported by investments to integrate and optimize Distributed Energy Resources ("DERs") such as rooftop solar and EVs, a focus on including Environmental Justice ("EJ") factors in distribution planning, and ensuring investments are right-sized and targeted through the Capacity Program. 5 TR 881. In order to optimize system costs, the Company's distribution organization is continuously seeking ways to improve how it plans and executes projects, including weekly reviews of current performance in meeting reliability goals, and quarterly reviews of the

distribution system health to proactively address the risk of asset failure. 5 TR 898-900. The Company is also seeking Investment Infrastructure and Jobs Act of 2021 ("IIJA") funding for reliability and resiliency projects. 5 TR 900.

The Company's proposed capital expenditures prioritize Company investments to achieve the important outcomes described in the Reliability Roadmap. 5 TR 906. The Company's projected SAIDI performance from Case No. U-21389 was 178 minutes in 2023 (based on the spending requested in that case), and the Company achieved a SAIDI of 176 minutes (excluding Major Event Days ("MEDs")). 5 TR 929. The Company projects that the investments described in the Reliability Roadmap, beginning with the investments sought as part of this case, will result in a SAIDI of approximately 135 minutes (excluding MEDs) by 2028, and 116 minutes by 2032. 5 TR 860, 929-930. This SAIDI improvement would place Consumers Energy in the second quartile of the Institute of Electrical and Electronics Engineers ("IEEE") SAIDI benchmark. 5 TR 862.

i. Criticisms of the Company's Distribution Planning are Unfounded and do not Support Reduction of Distribution Capital Expenditures

References in the Record: Kelly, 5 TR 866-869, 1025-1033, 1039-1043, Exhibits A-111 (MPK-19), A-245 (MPK-29); Denzler, 5 TR 2978-3002, 3026-3032, Exhibits CUB-30 through CUB-34, Coppola, 5 TR 2723-2329, Exhibits AG-1.1 through AG-1.3; Kenworthy, 5 TR 2659-2664

MNSC witness Joshua W. Denzler and Attorney General witness Sebastian Coppola presented various criticisms of the Company's Reliability Roadmap and distribution planning. As will be discussed in more detail below, these criticisms are unfounded, not supported by the record, and do not support arguments that there should be any reductions to the Company's important distribution investments that will enhance the reliability and resiliency of the system.

MNSC witness Denzler argued that the Company's planned spending cannot be trusted because the "Company's increase in capital investments has not made a discernable difference in any of its core reliability metrics." 5 TR 2981. But it would be incorrect to conclude that the Company's most recent distribution investments have resulted in no benefits. Since the development of the Company's distribution strategy beginning with the first EDIIP in 2018, investments have rapidly provided local benefits, such as in the areas of zonal health improvements and HVD line rebuilds. 4 TR 565, 5 TR 1027, 2024. However, given the size of the Company's system, it takes time for local benefits to accrue to a point where they are reflected in improved systemwide SAIDI. 5 TR 1027.

System deterioration is also a significant contributor to reliability performance that does not significantly improve even with increased investment. 5 TR 1028. Although there have been increased investments performed in recent years on the LVD system, the Company is still not investing at a pace at which the system is deteriorating. 5 TR 1027. Absent investments that are made at the same rate the system is deteriorating, the Company's well-targeted investments will take time to deliver systemwide improvements. *Id*. And although Mr. Denzler seeks to minimize the impact of worsening weather (5 TR 2983), the evidence shows that weather has been worsening and is expected to continue to get worse. 5 TR 1028.

Even considering the time it takes to reflect systemwide benefits, the rate of deterioration on the system, and worsening weather, the Company still has shown systemwide SAIDI benefits in recent years, with SAIDI improving from 233 minutes in 2019 to 176 minutes in 2023. 5 TR 923, 1027. Mr. Denzler is plainly wrong in his conclusion that the Company has not demonstrated the ability to efficiently and effectively deploy capital on the distribution system.

Mr. Denzler argued that consistency with the Reliability Roadmap is not in itself sufficient to approve the Company's projected distribution expenditures in this case. See 5 TR 2990. But the Company has not argued that the Commission should grant approval of the Company's projected expenditures in this case simply because they are consistent with the dollars in the Reliability Roadmap. Rather, the Company presented the Reliability Roadmap as Exhibit A-111 (MPK-19) in this case as part of the evidence supporting the reasonableness and prudence of the Company's planned distribution expenditures. The Reliability Roadmap provides additional detail and offers broader context to the necessary expenditures proposed in this case. 5 TR 1028-1029.

As to other specific criticisms of the Reliability Roadmap that Mr. Denzler lists (5 TR 2991-2992), Consumers Energy has provided detailed responses to much of that same criticism in its Reply Comments in Case No. U-20147, included here as Exhibit A-245 (MPK-29). Mr. Denzler quoted Staff's comments made in Case No. U-20147, characterizing them as showing "defects" in the Reliability Roadmap. 5 TR 2992-2994. While Staff offered constructive criticism and suggestions for future distribution plans, the Company has consistently collaborated with Staff in its distribution plans and does not agree that Staff's comments support a conclusion that the Reliability Roadmap is defective. 5 TR 1029. And while the Commission's September 26, 2024 Order in Case No. U-20147 stated desired changes for future distribution plans, the Commission concluded that the Company's Reliability Roadmap complied with the Commission's requirements for that filing. The Commission did not indicate that the Reliability Roadmap should be disregarded. 5 TR 1029-1030; see also MPSC Case No. U-20147, September 26, 2024 Order, page 142.

Mr. Denzler argued that the Company's exclusion of all-weather modeling for SAIDI and Customer Average Interruption Duration Index ("CAIDI") in the Reliability Roadmap fails to

capture the full customer experience. 5 TR 2995-2996. The Company's use of SAIDI excluding MEDs is consistent with the IEEE standard used across the industry to normalize for unpredictable weather – it is certainly not an attempt to be misleading about the Company's reliability performance. 5 TR 1030. Mr. Denzler also criticized the Reliability Roadmap because planned spending does not achieve the Company's SAIDI goal until 2029 and will only reach the second quartile of SAIDI. 5 TR 2997. As discussed, it will take time for systemwide SAIDI benefits to be realized, and the Company is proposing a reasonable and prudent ramp up in distribution work to reach those reliability goals. 5 TR 1030.

Mr. Denzler also criticized the Company's expected benefit projections for customer outage minutes avoided (which Mr. Denzler abbreviates as "CMI"). For example, he argued that LVD substations accounted for only 4% of the average SAIDI from 2019 through 2023, but the Company attributes 36% of its expected customer outage minutes avoided to this category. 5 TR 2999. Mr. Denzler also argued that the projected customer outage minutes avoided due to LVD substation investments is greater than the historical amount. 5 TR 3000.

Mr. Denzler's analysis fails to recognize that LVD substation outages are low-frequency, high-impact events. Substations have built-in redundancies that limit the ability of a single equipment outage to cause widespread customer interruptions, which has resulted in a relatively low historical SAIDI and customer outage minutes for these outages. 5 TR 1031. But when interruptions do occur, that can be widespread and long-lasting. *Id*. Thus, investments to reduce the likelihood of future outages have a large impact on the projected number of customer outages that would occur without the investment. 5 TR 1031-1032. As an example, if a transformer is at risk of failure that would cause 10,000 customers to lose power for 24 hours, then the Company will conclude that replacing the transformer will avoid those outages in the future even if there

have not yet been actual historical outages to consider. 5 TR 1032. This consideration of projected outage minutes avoided allows the Company to meaningfully compare the relative benefits of different potential projects. *Id*.

Mr. Denzler proposed that the Company develop a new benefit cost analysis framework for distribution planning, including the "ability to verify and validate assumed costs and benefits of the programs" and "robust data analysis leveraging the full capabilities of modern data tools." 5 TR 3030. Initially, and most importantly, Mr. Denzler's proposal for the development of a new (and likely costly) benefit cost analysis is not necessary because the Company has already evaluated the benefits and costs of its projects and presented them in this case. 5 TR 1032. It is also important to note that Staff has hosted technical conferences related to distribution benefit cost analyses in the past and recommended future stakeholder processes. *Id*. If the Commission believes that a new benefit cost framework should be developed, it should be done through a more collaborative process with stakeholder input and Commission guidance. 5 TR 1032-1033.

Mr. Denzler suggested a starting point for a new benefit cost analysis could be a "pilot" for LVD Lines Reliability. 5 TR 3029. LVD Lines Reliability is the largest distribution program, with Exhibits A-127 (DAL-1) and A-128 (DAL-2) including hundreds of individual projects. 5 TR 1033. Seeking to develop a framework with the numerous factors suggested by Mr. Denzler, and attempting to apply it to all of the LVD Lines Reliability, would not represent a reasonable limited pilot. *Id*. The Company identifies areas on the distribution system that will benefit from reliability investments, and pursues the appropriate projects on a least-cost-best-fit basis. *Id*. The Company should not be required to develop a completely new benefit cost analysis for distribution planning which incorporates Mr. Denzler's preferences, particularly in some short period of time. 5 TR 1032. Any such requirement is unnecessary and unreasonable.

Attorney General witness Coppola argued that the Reliability Roadmap does not provide sufficient benefits compared with the projected costs. 5 TR 2729. As discussed above, investments in the system are required to improve reliability, but it takes time to realize systemwide SAIDI improvements, particularly considering deterioration and worsening weather. 5 TR 1040. In addition, not all SAIDI improvements with be accomplished at the same cost – some improvements may require projects that are more complex and costly. 5 TR 1040-1041. But that does not mean that the Company should stop striving to improve the system. The investments at the levels identified in the Reliability Roadmap put the Company on the path to a SAIDI of 116 minutes, which is in the second quartile compared to the Company's peers. 5 TR 1041. The Company submits that building a grid that delivers better-than-average reliability is worth the projected cost.

Mr. Coppola argued that the proposed spending levels do not have adequate assurance of near term improvements simply because the Company has not identified a date by which single outage events will affect no more than 100,000 customers and by which no customer will be without power for more than 24 hours following an outage event. 5 TR 2726. These two Company goals represent a longer-term vision for a grid capable of achieving this type of performance – the Company is not at this time proposing a concrete plan that will result in accomplishing these goals. 5 TR 1042. The Company provided throughout its testimony and exhibits, including in the Reliability Roadmap, the defined reliability benefits that are planned to be achieved through the distribution investments proposed in this case.

The Attorney General regularly criticizes the Company's distribution reliability performance and the pace of improvement. 5 TR 1043. In this case and in the Reliability Roadmap, the Company is proposing a plan to speed up those improvements, but that plan requires

both capital expenditures and maintenance spending. Mr. Coppola's recommended reductions in proposed grid investments and maintenance spending is at odds with the Attorney General's oft-stated media demands for improved reliability. *Id*. The Commission should consider this inconsistency in evaluating the reasonableness of the Attorney General's proposed reductions in spending throughout this case.

Company witness Michael P. Kelly discussed the consideration of Non-Wires Solutions ("NWS") in the Reliability Roadmap, stating that the concept "is not ready for consideration as a repeatable, programmatic approach to improving reliability." 5 TR 868. CEO witness William D. Kenworthy argued that the Company is mischaracterizing the nature of NWS when it states that NWS is not an off-the-shelf option. 5 TR 2660. CEO recommended that the Commission require the Company to create an NWS framework in its next distribution grid plan that identifies congestion points on the distribution grid as good candidates for NWS. 5 TR 2664.

Consumers Energy's concern with NWS is the previous proposals the Company has seen that NWS should be considered for a significant proportion of distribution investments. 5 TR 1020. In that context, NWS would need to be standard and repeatable given the large number of distribution projects. 5 TR 1020-1021. The Company agrees that the targeted energy waste reduction ("EWR") and demand response ("DR") at the Swartz Creek and Four Mile pilots provided some benefits to participating customers. 5 TR 1021. But NWS is not always a zero-regrets proposition. For example, in the Four Mile pilot, the Company was required to perform the traditional substation project anyway. While in that situation there was still time to execute that project, in other situations, the reliability or capacity issues may be more severe and may require more immediate attention. 5 TR 1021.

Although Mr. Kenworthy identified NWS pilots being performed in other locations, the pilots he identified seem to have achieved mixed results, or results are still being determined, or results were for a smaller mostly rural utility that may not correspond to the Company's experience. 5 TR 1022. However, the Company is engaged in Electric Power Research Institute ("EPRI") initiatives that are studying NWS, and continues to consider NWS in a manner that does not risk grid reliability. *Id*. The Company does not agree that the Commission should require the Company to develop NWS by some near-term date. As discussed, the Company cannot design individualized NWS for large numbers of distribution projects. *Id*.

b. <u>High Voltage Distribution</u>

References in the Record: Kurdziel, 5 TR 2003-2134, Exhibits A-123 (KMK-1) through A-126 (KMK-4), A-247 (KMK-5) through A-249 (KMK-7)

The HVD system is the backbone of the Company's distribution system, meaning that thousands of customers can face interruptions as the result of single outage on the HVD system. 5 TR 2005. The Company's HVD system consists of HVD Lines and Substations that distribute electricity to the LVD substations. 5 TR 2008. The HVD system includes 145 HVD substations, 4,600 miles of HVD lines, and 164 strategic customer substations. 5 TR 2008. To mitigate the widespread customer impact of HVD outages, the HVD system is largely a looped system with built-in redundancies to minimize the customer impact due to loss of any single component. 5 TR 2009. The projected investments in the HVD system will address asset health, improve HVD system performance, and improve reliability for customers by proactively repairing and replacing assets before they fail. 5 TR 2005. These investments will reduce the risk of future outages, ensure that the HVD system continues to provide a reliable backbone infrastructure, and accelerate the improvements in HVD SAIDI. 5 TR 2010.

i. HVD Reliability

References in the Record: Kurdziel, 5 TR 2017-2067, Exhibits A-123 (KMK-1) through A-126 (KMK-4)

The HVD Reliability sub-programs ensure the long-term safe and reliable operation of the HVD system. The HVD Reliability sub-programs include the planned work in HVD Lines Reliability, HVD Substations Reliability, HVD Lines and Substations Rehabilitation, and System Protection. 5 TR 2017.

a) HVD Lines Reliability

References in the Record: Kurdziel, 5 TR 2019-2032, 2124-2125, 2129-2132, Exhibits A-125 (KMK-3) through A-128 (KMK-6); Coppola, 5 TR 2768-2771; Denzler, 5 TR 3014-3016, Exhibit CUB-36

In the HVD Lines Reliability sub-program, the Company identifies lines with consistently poor reliability performance and identifies the best remediation approach that will cost-effectively reduce risk and prevent future outages. 5 TR 2020. The Company identifies and assesses the asset health and risks related to conductor, insulators, and poles, and addresses those identified risks through line rebuilds, pole top rehabilitations, and pole replacements. *Id*. The planned projects are identified in Exhibits A-125 (KMK-3) and A-126 (KMK-4). The HVD Lines Reliability sub-program also includes line sensors which identify abnormal line conditions, allowing the Company to investigate and address issues before a failure occurs. 5 TR 2019. The HVD Lines Reliability sub-program primarily reduces asset health risk, but also plays a key role in reducing SAIDI. 5 TR 2020-2021.

The Company projects capital expenditures of $51.162 million in the bridge period and $90.995 million in the test year for HVD Lines Reliability. 5 TR 2026-2027. Cost projections are based on the combined costs of the planned projects, with individual project cost projections based on past actual project expenditures considering project location, expected site conditions, material

needs, and any known anomalies in costs. 5 TR 2028. The workplan for the bridge period is expected to prevent over 2,983,000 customer outage minutes, and the workplan for the test year is expected to prevent over 5,083,000 customer outage minutes. 5 TR 2027. The planned capital projects for the bridge period and the test year, and their locations and benefits to reliability, are shown in Exhibits A-125 (KMK-3), page 1, and A-126 (KMK-4), page 1. 5 TR 2028.

Attorney General witness Coppola stated that it is "perplexing why a doubling of pole replacement activity is now necessary" when there has been no change in pole inspection and replacement criteria. 5 TR 2768-2769. Mr. Coppola proposed to spread the increase in pole replacements over a three-year period, recommending a $7.205 million reduction in the bridge period and a $4.986 million reduction in the test year. 5 TR 2669-2770. The Commission should reject this proposed reduction. While Mr. Coppola is correct that there has been no change in inspection criteria, the poles that the Company identified for replacement in the bridge period and test year are poles that were already identified through inspections as needing replacement. The Company's proposed expenditures in this case will address this backlog of poles needing replacement. 5 TR 2124. If the Company replaces the poles at a slower rate, known deteriorated poles will remain on the system longer, increasing the risk of outages and the risk to safety. 5 TR 2124-2125. The Commission should approve the full amount requested for HVD pole replacements.

Mr. Coppola also recommended reducing the rate of increase in Right-of-Way ("ROW") costs to a 43% increase to match the 43% increase in line rebuilds over the bridge period, resulting in a proposed $1.944 million test year reduction. 5 TR 2770-2771. The Commission should reject this recommended reduction. The Company often incurs ROW costs in a given year for projects that are not scheduled to take place until later, and the costs of securing ROW can increase

depending on property owners' willingness to work with the Company in securing the necessary rights. 5 TR 2125. In addition, ROW work may be needed for other work besides HVD line rebuilds, such as to bring existing easements to current standards to provide for access by modern construction and tree clearing equipment. 5 TR 2125. Thus, it is not correct to assume that ROW costs will increase by the exact same percentage as HVD line rebuild costs, and Mr. Coppola's proposed reduction based on this assumption should be rejected.

MNSC witness Denzler argued that the Company is not targeting its reliability investments to areas with the highest reliability risk, that there is no apparent comparison of cost when evaluating options to improve HVD reliability, that the Company's planning should be more robust, and that the Company's Reliability Roadmap is flawed, recommending that the Company's HVD Reliability spend be held at 2023 levels, which results in a $120.7 million disallowance. 5 TR 3014-3016. Mr. Denzler's arguments are flawed and, in many respects, plainly incorrect and based on false premises. The Commission should reject Mr. Denzler's recommended disallowance.

As an initial matter, Section III.A.1.a of this Initial Brief addresses Mr. Denzler's claim that the Company's Reliability Roadmap is "flawed," and explains that Mr. Denzler's arguments are unfounded and should be rejected.

As to the few HVD Reliability investments that Mr. Denzler seeks to criticize, Mr. Denzler claimed that the Company replaces or rebuilds HVD assets based solely on age and configuration rather than based on the condition of the assets. 5 TR 3015. Mr. Denzler's claim is incorrect and reflects a misunderstanding of the Company's planning and prioritizing process. The Company performs HVD line rebuilds and pole top rehabilitation projects for those assets in poor health, and projects are planned based on the past performance (or reliability) of the line and the results of

inspections. 5 TR 2130-2131. The fact is that the Company does not replace distribution assets just because they are old, but assets beyond their expected lifespan are more likely to need to be replaced based on their condition that is monitored through inspections. 5 TR 2131.

Similarly, Mr. Denzler's suggestion that the Company's asset health model does not consider several types of information is also incorrect. Consumers Energy explained to MNSC in discovery that the Company's asset health model considers multiple inputs, such as asset type, manufacturer, condition, actual outages, level of degradation obtained during inspections, maintenance, response to events, or annual diagnostic testing to provide a holistic view of the asset's health. 5 TR 2131. Thus, contrary to Mr. Denzler's assertion, the asset health model considers a wide variety of information to determine the projects that will offer the most benefits to reliability.

Mr. Denzler criticized the model because of the Company's statement that the model does not capture failures ahead of time. But the Company's discovery response to which Mr. Denzler referred was responding to MNSC's request for the Company to provide the "accuracy" of the model. 5 TR 2131. The Company's response was meant to convey that the asset health model does not predict a date and time when an asset will fail in a manner that would allow for verification of the accuracy of the model against what actually occurs. 5 TR 2131. Rather, the asset health model provides indications of where reliability issues will likely occur, which allows the Company to begin planning where to focus its expenditures to address the biggest risks on the system.

MNSC witness Denzler's criticisms of the Reliability Roadmap, claims that the Company replaces assets based on age, and concerns with the asset health model do not accurately comprehend the Company's careful planning and project prioritization. Consumers Energy fully supported the reasons for its HVD Reliability investments in this case, and the Commission should

reject Mr. Denzler's proposed disallowances of these expenditures that will promote the safety and reliability of the system.

b) HVD Substations Reliability

References in the Record: Kurdziel, 5 TR 2032-2040, Exhibits A-125 (KMK-3) and A-126 (KMK-4)

In the HVD Substations Reliability sub-program, the Company makes needed replacements of existing substation equipment to ensure the long-term safe and reliable operation of HVD substations. 5 TR 2023. While HVD substations are designed with redundancies, the HVD system is sometimes temporarily configured to remove a layer of redundancy to facilitate repairs or construction. If multiple components fail at the same time, it can result in customer outages that have significant SAIDI impacts – two minutes of SAIDI or more for a single outage. 5 TR 2032-2033. This sub-program includes fixing and fortifying circuit breakers, transformer bushings, and switches that are in poor health. 5 TR 2033. The Company also performs other targeted replacements for specific equipment such as voltage transformers and substation lightning arresters. 5 TR 2036. To identify the substation equipment that needs to be replaced, the Company performs inspections such as infrared inspections, routine substation patrols, and diagnostic testing of transformer and breaker oil and gases. 5 TR 2035. Based on these inspections, 13% of HVD substations are a high priority for repair or replacement and an additional 19% are of moderate concern. 5 TR 2033. While HVD substations are not a large overall contributor to SAIDI, HVD Substations Reliability investment does improve overall reliability for customers – in addition to reducing asset health risk. 5 TR 2034.

The Company projects capital expenditures of $7.3 million in the bridge period and $11.4 million in the test year for HVD Substations Reliability. Cost projections are based on

planned projects, with individual project cost projections based on comparable projects of similar scope. 5 TR 2038.

c) System Protection

References in the Record: Kurdziel, 5 TR 2059-2067, Exhibits A-125 (KMK-3) and A-126 (KMK-4)

The purpose of HVD System Protection is to de-energize, as quickly as possible, the minimum amount of the electric network that has experienced an electrical fault, to isolate the fault, and to mitigate damage to other equipment. 5 TR 2059. Failure of protection systems during a fault can result in unnecessary customer outages, and can even lead to cascading outages and widespread blackouts. 5 TR 2059. Protection system failures can also result in extensive damage to the electric network, which can make it take much longer to restore service to customers while additional equipment is repaired or replaced. 5 TR 2060. Electric protective systems also protect the public from the safety hazards that can result from failure to correctly de-energize an electrical fault. 5 TR 2059-2060. The System Protection sub-program replaces obsolete relays that are reaching end of life with new digital devices that have fault monitoring capabilities to improve reliability and offset future Operating and Maintenance ("O&M") costs. 5 TR 2062.

The Company projects capital expenditures of $4.562 million in the bridge period and $5.201 million in the test year for HVD System Protection. 5 TR 2064. Cost projections are based on past work order costs for replacing similar equipment, considering the complexity of the specific relay schemes and the need to replace control enclosures. 5 TR 2065.

d) HVD Lines and Substations Rehabilitation

References in the Record: Kurdziel, 5 TR 2041-2058, 2126-2128, Exhibits A-125 (KMK-3) and A-126 (KMK-4); Coppola, 5 TR 2771-2775, Exhibits AG-1.12

The HVD Lines and Substations Rehabilitation sub-program includes: (1) repair or replacement of 46 kV and 138 kV lines equipment where failure has not yet occurred but where

there is an increased risk of failure that would threaten customer reliability or system operability; and (2) repair or replacement of HVD substation equipment and even the entire substation. 5 TR 2041. This sub-program includes pole replacements, pole top assembly replacements, switch replacements, miscellaneous other replacements, HVD substation rebuilds, transformer replacements, and other substation equipment replacements. 5 TR 2041. These proactive replacements address imminent failures identified during inspection that require a short cycle prioritization to correct in order to maintain system and customer reliability. 5 TR 2042, 2048-2049. The Company identifies these imminent failures through pole inspections, helicopter inspections, biannual ground inspections, motor operated air break switches ("MOABS") testing, infrared inspections, and inspections of individual pieces of substation equipment. 5 TR 2045, 2049.

The Company projects capital expenditures of $39.881 million in the bridge period and $70.9 million in the test year for HVD Lines and Substations Rehabilitation. 5 TR 2053. HVD lines investment category cost projections for the bridge period are to address anomalies and defects identified from previous inspections, and test year projections are increasing for poles, pole tops, and switches to address the growing number of anomalies identified during prior inspections and to address those identified during the test year. 5 TR 2055. Projected spending is based on the five-year unit cost average multiplied by the planned number of projects. *Id*. HVD substation rehabilitation work is projected based on the projects identified in Exhibits A-125 (KMK-3), page 3, and A-126 (KMK-4), page 3.

Attorney General witness Coppola argued that the Company did not justify the increase in the pole top assembly replacements category and recommended spreading the increase over three years, which results in a recommended test year reduction of $3.69 million. 5 TR 2772-2773. The

Commission should reject this reduction. Priority 3 anomalies in pole top assemblies represent imminent failure risk and are replaced in HVD Lines Rehabilitation, and Priority 3 anomalies have increased over the last five years. 5 TR 2043-2044, 2127. The pole top assemblies that the Company included for replacement in this case are units that the Company has already identified for replacement during inspections. 5 TR 2126. A slower replacement rate will leave more of these deteriorated pole top assemblies on the systems, increasing outage risks. *Id*. The Commission should approve the Company's projected test year expenditures to support the Company addressing the backlog for replacement.

Mr. Coppola also recommended that the Commission hold the projected spending on HVD Substation Replacements to the three-year historical average plus inflation because of his argument that it is not clear why replacing two substations in the test year would cost approximately $20 million more than replacing two substations in the bridge period. 5 TR 2774. This recommendation amounts to a $9.393 million disallowance in the bridge period and a $27.499 million disallowance in the test year. 5 TR 2775. The Commission should reject this reduction.

Mr. Coppola's proposed reduction is based on a unit cost analysis, but simply applying unit costs is not a suitable way to project HVD Substation Replacements. HVD substation rebuilds are very large projects that can span more than one year, and the Company likely performs some work on more than two projects in any given year. 5 TR 2051. In the bridge period, the Company is completing work on the Bliss substation rebuild and the new Celery substation, and also beginning work on the North Belding and Buskirk substation rebuild projects. 5 TR 2051, Exhibit A-125 (KMK-3), page 3. In addition to continuing work on the North Belding and Buskirk substation

rebuilds in the test year, the Company will begin work on the Alma and Blackstone substation rebuild projects. 5 TR 2052, Exhibit A-126 (KMK-4), page 3.

The projects to replace or rebuild substations are based on the unique needs of the particular substation, and the cost projections for these types of replacements cannot be accurately determined by just looking at historical unit costs. For example, a transformer alone can cost between $1 million and $5 million depending on size and voltage rating. 5 TR 2128. Consumers Energy identified the specific substation rebuild projects planned for the test year, and provided the specific cost projections associated with those projects. See Exhibit A-126 (KMK-4), page 3. The Attorney General has not offered any convincing reason to question the projections the Company provided for these individual projects. The Commission should approve the Company's well-supported cost projections, and reject the Attorney General's artificial reductions to these costs.

ii. HVD Lines and Substations Capacity

References in the Record: Kurdziel, 5 TR 2068-2078, Exhibits A-125 (KMK-3) and A-126 (KMK-4)

The HVD Lines and Substations Capacity sub-program addresses: (i) capacity needs on the HVD system according to HVD planning criteria; (ii) work to accommodate new interconnections to the HVD system; (iii) work to improve functionality through standards, upgrades to protection, and operability of the system; (iv) coordination with transmission infrastructure additions; and (v) support for ROW acquisition projects. 5 TR 2068. Investments in this sub-program are needed to serve customers and maintain the safety and reliability of the grid by ensuring that the HVD system can accommodate new and changing technologies (such as EVs), preventing future overloads, and improving system safety by avoiding wire downs and equipment failures. 5 TR 2069.

The Company projects capital expenditures of $33.008 million in the bridge period and $30.503 million in the test year for HVD Lines and Substations Capacity. 5 TR 2074. Cost projections were developed using derived unit costs, where available, based on historical actual costs for similar projects. 5 TR 2075. Some costs were further refined considering individual project characteristics such as the project location, expected site conditions, and updated material and labor costs. 5 TR 2075-2076. Planned projects for HVD Lines and Substations Capacity are identified in Exhibits A-125 (KMK-3), page 5, and A-126 (KMK-4), page 5.

iii. Electric Other Program

References in the Record: Kurdziel, 5 TR 2078-2089

The Electric Other Program includes the sub-programs (i) Computers and Equipment, (ii) Tools, (iii) System Control Projects, and (iv) Grid Technologies. 5 TR 2078-2079. Total projected Electric Other bridge period expenditures are $11.264 million and test year expenditures are $8.389 million.

a) Computers and Equipment

References in the Record: Kurdziel, 5 TR 2079-2080

The Computers and Equipment sub-program includes the capital costs to purchase and replenish computer equipment for electric distribution purposes. The Company projects capital expenditures of $58,000 in the bridge period primarily for new field devices and $75,000 in the test year. 5 TR 2081.

b) Tools

References in the Record: Kurdziel, 5 TR 2080-2086

The Tools sub-program includes the purchase of new and replacement tools for utility workers where the tools are priced over $1,000 per item. 5 TR 2080. This sub-program includes outfitting new Company trucks with standard packages of essential tools to ensure that crews go

into the field with appropriate equipment, with the purchase plan based on the Company's fleet acquisition and deployment plan. 5 TR 2081. Crews and trucks that have the proper tools support safe and timely responses to outages, safe and efficient installation of new services, and productive completion of projects. *Id*. The Company projects capital expenditures of $9.068 million in the bridge period and $8.035 million in the test year for Tools based on prices quoted from vendors for the specific models and the needs of the Company for truck tool kits and other capital tools. 5 TR 2082.

c) System Control Projects

References in the Record: Kurdziel, 5 TR 2086-2089

The System Control Projects sub-program includes projects to improve management of the distribution system by improving operations of control centers, streamlining operations, and improving remote control capabilities to enhance safety and reliability. Projects in this sub-program include operating technology enhancements and operations center modifications. 5 TR 2086. Improving monitoring and control capabilities on the distribution system streamlines operations and reduces the impact of a single fault, thereby reducing interruptions for customers. The technology enhancements and control room modifications better enable employees to support the provision of safe and reliable electric service. 5 TR 2088. The Company projects capital expenditures of $1.689 million in the bridge period and $279,000 in the test year for System Control Projects. 5 TR 2088.

d) Grid Technologies

References in the Record: Kurdziel, 5 TR 2089

Grid Technologies expenditures are for the Company's Enterprise Corrective Action Plan, which was detailed in Case No. U-21389 and approved by the Commission in that case. The

Company is projecting $450,000 in the bridge period to complete this effort in 2024, with no spending identified after that. 5 TR 2089.

iv. HVD Strategic Customers New Business

References in the Record: Kurdziel, 5 TR 2090-2098, 2128-2129, 2132-2134, Exhibits A-125 (KMK-3), A-126 (KMK-4), and A-249 (KMK-7); Kelly, 5 TR 1055-1056; Coppola, 5 TR 2776-2778; York, 5 TR 3359-3360; Albers, 5 TR 3231-3233

The overall New Business Program includes the capital costs of connecting new customers to the distribution grid. The Company is generally required to provide the requested interconnections. 5 TR 2090. The HVD Strategic Customers New Business category consists of the capital costs to meet the new business needs of large Commercial and Industrial ("C&I") customers that are too energy intensive to be served by the LVD system. 5 TR 2090. This category of the New Business Program includes both existing customers and proposed new customers looking to locate in Michigan, and typical investments include dedicated substations and their interconnection to the HVD system with poles, conductors, and metering. 5 TR 2090. This sub-program (1) benefits current C&I customers' expansion of their businesses and facilities, (2) provides for new large customer load additions, which benefits the Michigan economy by offering job development and other state and local revenue streams, and (3) benefits all of Consumers Energy's customers with large customer additions that spread costs across a larger customer base. 5 TR 2097.

The Company projects $107.642 million in the bridge period and $59.673 million in the test year for HVD Strategic Customers New Business. 5 TR 2092. Projected spending is primarily based on known and planned projects where customers have signed agreements with the Company committing to the projects. 5 TR 2092; Exhibits A-125 (KMK-3), page 6, and A-126 (KMK-5), page 6. Projected spending also includes $10.2 million in the bridge period and test year to purchase transformers with long lead times to support meeting customer timeline needs for other

high probability projects. 5 TR 1092. Purchasing these transformers will reduce the time it takes to provide electric service to potential customers that are looking for a site where they can start production as soon as possible. This will help to attract large new business opportunities to Michigan. 5 TR 2095.

Attorney General witness Coppola recommended removal of the Company's proposed $10.2 million in the bridge period and test year for the Company to purchase high probability project transformers, arguing that it is too risky to purchase transformers without being certain of how the transformer will be used. See 5 TR 2776-2778. The Commission should reject Mr. Coppola's recommendation because it is too risky to avoid these transformer purchases.

The Company expects C&I development in Michigan to continue to expand, which will result in increased demand in HVD Strategic Customers New Business projects. 5 TR 2094. In working with the Michigan Economic Development Corporation ("MEDC") and other local economic development groups, it has become clear that potential C&I customers consider if a site is ready and able to meet customer project timelines when considering where to locate. 5 TR 2095. The Company has learned that the largest bottleneck in developing these sites is typically transformer procurement.

Consumers Energy supported 133 requests for proposals from potential large customers in 2022, 153 in 2023, and 12 in the first two months of 2024. 5 TR 2096. All of these projects would require long lead-time transformers, and if the Company does not have a supply of transformers ready on short notice, then Michigan could lose out on these potential economic development opportunities. *Id*. For that reason, the Company has proposed spending in this case to purchase long lead-time transformers so that the Company can have these transformers on hand, and the provision of electric service is not the deterrent to these developments in Michigan. 5 TR 2095.

In addition, these transformers that the Company is proposing to keep on hand will be of a common size and voltage so that they are compatible with a large portion of the Company's system. 5 TR 2096-2097. Transformers on hand could be reallocated to other substation projects in the Reliability and Capacity programs as needed, which will improve reliability by supporting quicker proactive replacement of units in poor health. 5 TR 2097. The Company could also use these transformers as strategic spares in case there is a failure of an existing transformer. As Company witness Keith M. Kurdziel testified, "building up a supply of transformers is a no-regrets investment." *Id*. The Commission should approve this initiative that will reduce barriers to bringing businesses to Michigan. 5 TR 2129.

MEIU witness John D. Albers recognized that "substantial delays concerning the availability of transformers is a significant problem," and recommended that the Commission require the Company to identify long lead time equipment associated with interconnecting advanced energy technologies in its next rate case and develop and propose a system of maintaining an inventory of such equipment. 5 TR 3232-3233. The Company is also concerned about the availability of transformers, which is why the Company has proposed approval of the ability to have a supply of transformers on hand for use as needed. 5 TR 1056. The Company is seeking to take proactive measures to maintain adequate supplies, and a Commission directive to perform a study or make a proposal in its next rate case is not necessary. In addition, Mr. Albers' proposal would require the Company to evaluate potential hardware needs over the next 10 years as part of a study, and it would not be reasonable to require the Company to perform such a detailed analysis prior to the Company's next electric rate case. 5 TR 1056. The Commission should not require the Company to perform this proposed study.

ABATE witness Jessica A. York recommended removed of $5.093 million to develop a new dedicated customer substation for a manufacturing plant in northwest Michigan, arguing that it is unclear if an extraordinary facilities agreement ("EFA") was ever signed by the customer and that the concept approval stated that an incremental distribution facilities charge will cover 100% of the upfront cost of the project. 5 TR 3359-3360. The Commission should reject this recommended reduction. During discovery, the Company provided updated information regarding this project which indicated that the customer had signed the EFA. 5 TR 2132, Exhibit A-249 (KMK-7). The response also indicated that the project is subject to an Incremental Facilities charge as part of the Large Economic Development Rate ("LEDR"), which is an alternative to the customer paying an upfront facilities cost. 5 TR 2132. Under the LEDR, the customer is billed a monthly incremental facilities charge over the life of the contract, and this charge ultimately covers the upfront cost of the project. *Id*. As the Company receives the charge, it offsets the revenue requirement of the investment, which the Company accounts for in the rate case. 5 TR 2132-2133. Nonetheless, the investment amount is included in rate base, subject to offset as the customer pays the monthly charge. 5 TR 2133. Accordingly, the Commission should not adopt the recommended disallowance.

v. HVD Lines and Substations Demand Failures

References in the Record: Kurdziel, 5 TR 2098-2108

The Demand Failures Program includes the capital expenditures involved in replacing failed equipment to restore service to customers. Demand Failures work is emergent and is planned, prioritized, and completed as issues arise. 5 TR 2098-2099. The HVD Lines and Substations Demand Failures sub-program includes the capital replacement of failed 46 kV and 138 kV lines and substation equipment to restore customer service and maintain reliability. The sub-program replaces assets that have failed in the field, including HVD substation equipment,

HVD poles and switches, and HVD cross-arms and insulators. 5 TR 2099. This sub-program is essential for the restoration of service to customers for the Company to meet its obligation to serve. 5 TR 2100.

The Company projects $5.833 million in the bridge period and $5 million in the test year for HVD Lines and Substations Demand Failures. 5 TR 2104. The projections are based on the historical four-year average, updated to reflect known circumstances. 5 TR 2105.

vi. HVD Asset Relocations

References in the Record: Kurdziel, 5 TR 2108-2114

The HVD Asset Relocations sub-program supports the non-reimbursable relocations of 46 kV and 138 kV lines required to accommodate the use of the public ROW and transmission project work. The cost of relocating lines in the road ROW, and in some cases on private property, is typically the Company's responsibility. In other cases, the requesting party will reimburse the Company for the cost of the relocation. 5 TR 2109. Parties requesting relocation include municipalities and other government agencies, transmission owners, private landowners, and internal Company departments. *Id*. This sub-program not only performs relocations at the request of customers and other external parties, but also helps improve reliability through the installation of new equipment that meets current design standards. 5 TR 2112.

The Company projects $1.050 million in the bridge period and $900,000 in the test year for HVD Asset Relocations. The bridge period and test year projections are consistent with the amount approved for the test year in Case No. U-21389. 5 TR 2112.

vii. The Commission Should Reject Staff's Blanket Reductions in Projected HVD Expenditures

References in the Record: Kurdziel, 5 TR 2023-2025, 2114-2123, Exhibits A-125 (KMK-3) and A-126 (KMK-4); Kelly, 5 TR 1002-1004, Exhibit A-111 (MPK-19); Boutet, 5 TR 3704-3713, Exhibits S-11.1 and S-11.2

Staff witness Ryan Boutet noted that the Company's total projected HVD expenditures represent increases over the five-year average of HVD expenditures, including a 133% increase in the test year. 5 TR 3705-3706. Mr. Boutet stated that Staff does not support these proposed increases because of Staff's position that these expenditures do not provide sufficient reliability benefits in the form of SAIDI minute reductions. 5 TR 3707. Based on this argument, Staff proposed bridge period and test year HVD expenditures based on a five-year average plus inflation for most programs, resulting in a proposed disallowance of about $287 million - $125.928 million in the bridge period and $161.573 million in the test year. 5 TR 3710. The Commission should reject this blanket reduction to the Company's proposed improvements in the HVD system.

Staff's recommended $287 million reduction based on a perceived lack of SAIDI benefit ignores the fundamental nature of the HVD system. As discussed above, the HVD system is the backbone of the distribution system with redundancies in place that seek to avoid widespread and lengthy service interruptions. 5 TR 2117. HVD work that seeks to maintain these redundances may not result in a significant reduction to existing SAIDI, but is performed to avoid substantial customer outage minutes in the future. 5 TR 2117-2118. Assets are deteriorating on the HVD system, and the Company's investment plan presented in the Reliability Roadmap addresses this significant asset health risk. 5 TR 2118.

Mr. Boutet mentioned a few Staff concerns with specific program spending. Mr. Boutet stated that Staff did not support the increase in HVD pole replacements. 5 TR 3708. But there is no indication as to why Staff disagrees with the increase. The Company inspects HVD poles on

an approximate 12-year cycle, and HVD pole replacements are identified through the pole inspection program. 5 TR 2025. The proposed increase in investment in pole replacements in this case is to address poles that have already been identified through inspection as needing replacement, in addition to those expected to be newly identified by current inspections. 5 TR 2119.

Mr. Boutet also expressed Staff's concern with acceleration of substation transformer replacements, and noted that the Company estimated that the proposed HVD substation work will result in a reduction of 2 SAIDI minutes per year at an average annual cost of $83.6 million. 5 TR 3709. Mr. Boutet does not believe this is cost effective when comparing to LVD Overload Risk Reduction spending with an estimated 2.1 SAIDI minutes reduction per year at an average annual cost of $44.6 million. 5 TR 3709. But again, the expenditures associated with transformer investments do not contribute many minutes to SAIDI due to the redundancies on the HVD system. 5 TR 2120. If these investments are ignored and redundancies are not preserved, it increases the risk that widespread customer outages could occur, where a single outage could contribute two minutes or more to SAIDI. 5 TR 2120. The Company's proposed increased investment in HVD substations is important to mitigate the risk of substations failing and customers experiencing lengthy outages. *Id*. The transformers that have been identified for replacement in this case need to be replaced based on Company inspections. *Id*.

In addition, although Mr. Boutet identified an additional SAIDI benefit from LVD Overload Risk Reduction expenditures, the Commission should not treat these expenditures as mutually exclusive. LVD Overload Risk Reduction is part of the LVD Lines Capacity sub-program and represents a very different type of investment. 5 TR 2120. The Company is also

proposing to increase LVD Lines Capacity spending in this case, and there is no need to reprioritize more spending to that program.

Mr. Boutet also argued that the increase in HVD Lines Rebuild work is not cost-effective to improve reliability when LVD Lines contribute approximately 87% of SAIDI minutes. 5 TR 3709-3710. Again, the HVD system is largely looped to avoid widespread customer outages, and as a result the HVD system does not contribute as much to SAIDI minutes as the LVD system. 5 TR 2121. But that looped system needs to be maintained – when HVD lines are taken out of service, the remaining lines must be able to continue to serve until the loop and resulting contingency is restored. 5 TR 2121. All of the HVD line rebuild work that the Company is proposing as part of this case has been identified by the Company for replacement based on outage data and inspections, with concept approvals documenting their business cases.

The Company has identified 44% of its insulator assets as either vintage or victor, which represent concerned and high risk categories. 5 TR 2022. In addition, 14.4% of conductor assets are classified as high risk based on their condition. *Id*. The Company's projected increase in HVD Lines Reliability investments is to address these known risks. 5 TR 2023. Once the Company completes an HVD line rebuild, the data indicates that the line section will typically experience minimal line equipment-related outages. 5 TR 2023-2024.

Instead of proposing targeted disallowances based on the few areas of concerns that Mr. Boutet identified in his testimony, Mr. Boutet instead recommended broad and sweeping reductions to most of the Company's HVD spending programs. The Commission should reject the blanket reductions in Company expenditures because it ignores the substantial support the Company provided for performing the projects. Consumers Energy's evidence provided details of each HVD capital investment program, the basis of the planned investments, and the expected

benefits. The Company provided lists of identified actual projects, including associated benefits and costs. 5 TR 2123. The HVD capital investments support the overall objectives, including the reliability and asset health goals, in the Reliability Roadmap. 5 TR 2114.

Mr. Boutet's recommended reductions should also be rejected because they do not all reasonably follow from Mr. Boutet's concern with the reliability benefits of HVD spending. Mr. Boutet proposed disallowances to HVD Lines and Substations Capacity, Electric Tools, System Control, and HVD Strategic Customers New Business, which are programs that primarily address concerns other than reliability, even though Mr. Boutet does not assess the reasonableness of these programs. 5 TR 2122. Although Mr. Boutet's narrow focus on SAIDI contributions should not result in reductions to any of the Company's HVD spending, at a minimum it should not result in reductions to the Company's proposed spending in those programs that are not focused on addressing reliability. 5 TR 2123.

c. Low Voltage Distribution

References in the Record: Lynd, 4 TR 500-722, Exhibits A-127 (DAL-1) through A-129 (DAL-3), A-250 (DAL-4), A-251 (DAL-5)

The LVD system includes over 94,000 miles of lines made up of approximately 51,500 miles of primary overhead, 9,500 miles of primary underground, 30,000 miles of secondary overhead, and 3,000 miles of secondary underground. 4 TR 502. The LVD system has 13 different primary voltages, ranging from 2.4 kV to 24.0 kV. *Id.* LVD primary voltage is stepped down at the distribution pole top or padmount transformer to a secondary voltage, serving customers at voltages between 120 Volts and 480 Volts. 4 TR 502-503. There are over 2,000 LVD circuits that serve the Company's customers. 4 TR 503. The LVD system is largely a radial system that is not able to continue service to customers during outages. 4 TR 504.

i. LVD New Business

References in the Record: Lynd, 4 TR 506-517

The New Business Program includes the capital costs of connecting customers to the Company's distribution grid. The sub-programs under LVD include LVD Lines New Business, Metro New Business, and LVD Transformers. 4 TR 506.

a) LVD Lines New Business

References in the Record: Lynd, 4 TR 506-513, 701; Coppola, 5 TR 2732-2734, Exhibit AG-1.4

LVD Lines New Business includes the necessary overhead and underground distribution extensions and enhancements needed to complete new service connections. Projects are initiated by customers that the Company must serve. 4 TR 506. The projected spending will allow the Company to provide a new service installation to every customer who requests it. 4 TR 507. Projected capital expenditures are $142.153 million in the bridge period and $128.160 million in the test year. 4 TR 507. Projected expenditures are based on expected new service connections in the Company's service territory considering historic growth and other projections, such as those from the Home Builders Association of Michigan ("HBAM"). 4 TR 508.

Attorney General witness Coppola proposed a reduction of $11.352 million in the bridge period and $10.358 million the test year based on his methodology of using a three-year average unit cost plus inflation to project the costs, arguing that the Company needs to negotiate lower unit costs, shift more work to Company crews, or find other ways to reduce costs. 5 TR 2734. The Commission should reject this unrealistic recommended reduction. The Company's projected expenditures seek to capture the upward trends in unit costs that the Company has been experiencing. 4 TR 700. Unit costs in this sub-program increased by 2.3% from 2022 to 2023,

and the Company reasonably projected that unit costs for the bridge period and test year will increase at the same rate. 4 TR 510-511. The Company's projection reflects the increases that have been experienced in material and contractor costs. 4 TR 511.

Mr. Coppola's methodology of using a three-year historical average of unit costs does not appropriately account for these recent cost increases that have occurred. It would be unreasonable to lower these cost projections just because Mr. Coppola wants them to be lower and not because Mr. Coppola has offered any facts or data indicating that they can be lower. The Company looks for ways to reduce costs, including offering one-third fewer units to contractors in 2023 than it did in 2022. 4 TR 701. But the Company will still need to rely on contractors to perform this work to allow the Company's employees to continue to complete work in the Reliability program and other important areas. *Id*.

b) Metro New Business

References in the Record: Lynd, 4 TR 513-517, Exhibits A-127 (DAL-1) and A-128 (DAL-2)

The Metro New Business sub-program responds to the needs of new construction and existing metered locations served by the Company's Metro underground territories. To accommodate new business requests, the Company usually needs to extend both the underground civil infrastructure, such as ductwork, and the electrical system. 4 TR 513. The projected spending will allow the Company to provide new service installations to requesting customers in the Metro areas. 4 TR 514. Projected capital expenditures are $6.267 million in the bridge period and $3.917 million in the test year for Metro New Business. 5 TR 1874. Cost projections are based on historical trends, discussions with customers, and identified projects. 4 TR 517. Identified projects are included in Exhibits A-127 (DAL-1), page 1, and A-128 (DAL-2), page 1. 4 TR 514.

ii. LVD Demand Failures

References in the Record: Lynd, 4 TR 517-536

The Demand Failures Program addresses issues related to customer interruptions and failures of equipment on the distribution system. 4 TR 517. The sub-programs under LVD include LVD Lines Demand Failures, LVD Substations Demand Failures, LVD Metering, and Metro Demand Failures. 4 TR 518.

a) LVD Lines Demand Failures

References in the Record: Lynd, 4 TR 518-527, 701-702; Coppola, 5 TR 2735-2736, Exhibit AG-1.5

The LVD Lines Demand Failures includes capital expenditures that enable the Company to respond to day-to-day equipment failures and perform storm restoration work. 4 TR 518. The Company will categorize failures or damage by severity, with Priority 1 failures requiring immediate action and Priority 2 failures typically responded to within 60 days. 4 TR 519-520. The Company is performing focused visual line assessments to discover and fix these failures. 4 TR 520. The types of service restoration work within this sub-program include failed underground cable; failed distribution transformer; car pole accident; broken cross-arm, pin/insulator, or pole; and failed overhead conductor. 4 TR 523-524. The activities in this sub-program are essential for the restoration of service to customers and to fix Priority 1 and Priority 2 defects and improve reliability. 4 TR 524. Projected capital expenditures are $153.646 million in the bridge period and $147.408 million in the test year. 4 TR 525. These projections are based on the Company's anticipated completion of 29,000 orders in the bridge period and 27,800 orders in the test year. *Id*.

Attorney General witness Coppola argued that the Company needs to "reverse the current trend of cost increases," and proposed a reduction of $17.839 million in the bridge period and

$14.357 million in the test year based on a three-year historical average unit cost. 5 TR 2736. The Attorney General's proposed reduction should be rejected. The Company experienced a unit cost increase from $3,381 in 2020 to $5,058 in 2023 as a result of cost increases in wire, cable, and poles, as well as increases in the amount of materials used and time spent on each repair as part of the Company's proactive approach to address failures. 4 TR 527, 702. Based on this trend of increasing costs, the Company's projected $5,300 unit cost for the test year is reasonable. Just as discussed for LVD Lines New Business, a simple desire for costs to reduce to previous levels is not an accurate or reasonable method to project future costs. 4 TR 702. The Attorney General's demand that the Company magically reduce costs does not reflect the real world in which the Company operates, and should be rejected.

b) LVD Substations Demand Failures

References in the Record: Lynd, 4 TR 528-532, 702; Exhibit A-112 (MPK-20); Coppola, 5 TR 2737-2738

The LVD Substations Demand Failures sub-program includes the capital repair or replacement of failed LVD substation equipment to restore service to customers and maintain reliability of electric service. 4 TR 528. The work in this sub-program is essential to restore interrupted electrical service to customers and to the safe and reliable operation of the substation. 4 TR 529. Substations Demand Failure projects include the regulators, reclosers, transformers, and other equipment categories. 4 TR 528. Projected capital expenditures are $8.72 million in the bridge period and $9 million in the test year. 4 TR 529. Projected expenditures are based on projected failure rates considering historical failures. 4 TR 530.

Attorney General witness Coppola argued that the unit cost for regulators is too high, and recommended a reduction of $1.154 million in the bridge period and $1.276 million in the test year. 5 TR 2737-2738. The Commission should reject this reduction. Unit costs for regulators

have been increasing substantially since at least 2021, and the Company's bridge period and test year unit costs are in line with these actual increases. 4 TR 702. As noted in Exhibit A-112 (MPK-20), line 145, regulator unit costs were $34,246 in 2022 and $58,537 in 2023. Just as with LVD Lines Demand Failures, simply insisting that these costs should be lower does not in fact reduce these costs and fails to consider the recent cost increases that have in fact occurred, or the real world circumstances which are affecting the Company's costs.

c) Metro Demand Failures

References in the Record: Lynd, 4 TR 532-536

The Metro Demand Failures sub-program involves the replacement of failed cables, transformers, and civil infrastructure within the Company's Metro systems. Work in this sub-program includes the cable failure and replacement, transformer failure and replacement, and civil infrastructure failure and replacement investment categories. 4 TR 532. Projected capital expenditures are $642,000 in the bridge period and $550,000 in the test year for Metro Demand Failures. 4 TR 534. These projections are based on a three-year average of actual expenditures. 4 TR 535.

iii. LVD Asset Relocations

References in the Record: Lynd, 4 TR 536-552

The Asset Relocations Program includes capital investments to relocate electric assets to accommodate road, building, and other third-party construction projects and internal Company projects. LVD includes LVD Asset Relocations and Metro Asset Relocations. 4 TR 536.

a) LVD Asset Relocations

References in the Record: Lynd, 4 TR 536-546, Exhibits A-127 (DAL-1) and A-128 (DAL-2)

The LVD Asset Relocations sub-program responds to internal and external requests to relocate LVD lines and includes make-ready work to prepare LVD poles for third-party pole attachments. 4 TR 536. Government agencies request relocations for projects such as road and bridge widening or improvements, repairs to municipal facilities, and streetlight and traffic signal modifications. 4 TR 539. Private property owners request relocations for projects such as building additions, logistics, landscaping, and other construction projects. 4 TR 539. Make-ready work is typically requested by a communications company to place new attachments or modify existing attachments on Company poles. 4 TR 540. Although this sub-program primarily functions to serve customer requests, when old or obsolete equipment is replaced through this sub-program, reliability improves because of the new equipment and the latest standards implemented at the time. *Id*.

Projected capital expenditures are $52.856 million in the bridge period and $46.309 million in the test year for LVD Asset Relocations. 4 TR 542. Projected expenditures are based on recent trends in the number of relocation requests for third-party and customer-requested relocations, as well as projects identified in Exhibits A-127 (DAL-1), page 2, and A-128 (DAL-2), page 2. 4 TR 541, 543.

b) Metro Asset Relocations

References in the Record: Lynd, 4 TR 546-552, Exhibits A-127 (DAL-1) and A-128 (DAL-2)

The Metro Asset Relocations sub-program responds to internal and external requests to relocate or modify civil structures such as manhole chimneys and castings due to road grade changes. 4 TR 546. Relocation requests may be to accommodate civic improvement work or

requests to convert overhead electric systems to underground civil and electrical systems. 4 TR 546-547. This sub-program can also help improve reliability through the installation of new equipment. 4 TR 549. Projected capital expenditures are $8.117 million in the bridge period and $9.65 million in the test year for Metro Asset Relocations. 4 TR 549. These projections are based on the identified projects as shown on Exhibits A-127 (DAL-1), page 3, and A-128 (DAL-2), page 3. 4 TR 549-551.

iv. LVD Reliability

References in the Record: Lynd, 4 TR 552-645, Exhibits A-127 (DAL-1) and A-128 (DAL-2)

The Reliability Program ensures the long-term safe and reliable operation of the electric distribution system and supports the Company's SAIDI glidepath. 4 TR 552. The Company modeled different scenarios for increasingly severe weather as part of the Reliability Roadmap and is proposing a ramp-up in distribution system investment to improve reliability in the face of this worsening weather. 4 TR 552-553. This includes increased investments in system hardening, which is accomplished through the Reliability Program. 4 TR 553. LVD Reliability includes LVD Lines Reliability, LVD Substations Reliability, LVD Repetitive Outages, Metro Reliability, LVD Substations Rehabilitation, LVD Lines Rehabilitations, Metro Rehabilitation, and Resiliency. 4 TR 556.

a) LVD Lines Reliability

References in the Record: Lynd, 4 TR 557-582, 688-699, 703-707, Exhibits A-127 (DAL-1) and A-128 (DAL-2); Exhibit A-111 (MPK-19); Shi, 5 TR 3647-3657, Exhibits S-7.1 and S-7.2; Denzler, 5 TR 3006-3013, Exhibits CUB-25 through CUB-28, CUB-34; Coppola, 5 TR 2738-2743

The LVD Lines Reliability sub-program includes projects to ensure the long-term safe and reliable operation of the Company's LVD lines. 4 TR 557. LVD Lines Reliability investments are made in targeted circuit improvements, pole replacements, Automatic Transfer Recloser

("ATR") loops, circuit exit enhancements, and ROW and easement acquisitions. 4 TR 559. The Company uses several critical inputs and analyses to aggregate multiple data sources to identify areas to target investments that will deliver the greatest reliability improvements. 4 TR 557. The primary input for determining where to invest is the Reliability Analytics Engine ("RAE"), which is a database used to analyze outage incident history and electric operations performance. *Id*. The RAE combines data from various sources to produce monthly zonal analysis data and is used to determine zonal impact to LVD system reliability. 4 TR 558. The RAE will rank zones to target to maximize SAIDI reduction, including examination of consistency of outages, outage rate, customer impact, and current year outages. *Id*. In identifying potential LVD Lines Reliability projects, the Company also considers characteristics such as car-pole accident history and downed wires, as well as voltage deviations. 4 TR 559. The Company also uses Grid Archetypes to consider additional LVD circuit characteristics beyond just reliability metrics to ensure that all customers benefit equitably from the Company's investments. *Id*.

Targeted Circuit Improvements includes projects that reduce the non-standard voltage on the distribution system, improve zonal health, convert open-wire secondary to multiplex, and rejuvenate vintage underground cable. 4 TR 559-560. Pole replacements are completed in response to prior inspection results that identified poles at risk of failure, with the Company planning to clear the significant backlog of rejected poles. 4 TR 572-573. An ATR Loop is a set of reclosers that are installed between adjacent circuits that work to automatically restore power to many impacted customers, thus allowing customers to maintain power following an incident that would have caused more interruptions without the ATR Loop. 4 TR 575. Circuit Exit Enhancements provides additional safety by creating an isolation point for line workers in case a

substation becomes energized. 4 TR 577. ROW projects are to secure necessary land rights for LVD projects. *Id.*

Projected capital expenditures are $103.005 million in the bridge period and $298.72 million in the test year for LVD Lines Reliability. 4 TR 577. The increased LVD Lines Reliability investments are mostly driven by increased investments in zonal health improvements and pole replacements to deliver better reliability for customers. 4 TR 578. These investments are necessary to achieve the glidepath for reducing SAIDI as detailed in the Reliability Roadmap. 4 TR 578-579. Benefits for planned projects are identified in Exhibits A-127 (DAL-1), pages 4 through 23, and A-128 (DAL-2), pages 4 through 24, and include expected reductions in customer outage minutes of 31,831,000 in the bridge period and 86,429,000 in the test year. 4 TR 580.

(i). The Commission Should Reject Proposed Reductions in LVD Lines Reliability Improvements

Staff witness Jing Shi, P.E. recommended a reduction of $7.5 million in the bridge period and $206 million in the test for the Targeted Circuit Improvements investment category. 5 TR 3654-3655. Ms. Shi recognized that "Zonal health investments are a very important component within the LVD line reliability, as this investment has improved the reliability of the Company's LVD system by reducing the likelihood of an additional interruption." 5 TR 3653. Ms. Shi also stated that Staff "agrees with the Company that Zonal health investments are necessary and important for the long term LVD lines reliability performance," and that with past LVD lines reliability investment, "the Company has been on track to improve the performance and reduce the outage [sic]." *Id.* However, Ms. Shi stated that the historical spend was sufficient to make improvements in reliability, and that Staff could not find the differences between projects in the bridge period and the test year that would result in the projected increase. 5 TR 3653-3654. The

Commission should reject Staff's recommended reduction because it would reduce the planned reliability improvements on the LVD system.

Ms. Shi's claims that historical spending in zonal health improvements has been enough to sufficiently improve reliability is incorrect. 4 TR 691. The Commission, Staff, and other parties to this case have concluded that the Company's reliability is not sufficient at current levels. The Reliability Roadmap, Exhibit A-111 (MPK-19), analyzed the Company's distribution asset health and the ability to deliver improved reliability as weather becomes worse. 4 TR 692. The Company's proposed investments in this case reflect the planned spending that is needed toward reaching the reliability goals presented in the Reliability Roadmap. *Id*. Ms. Shi points to Company witness Donald A. Lynd's statement that zonal health improvement work has produced, on average, a 64% reduction in outages within the targeted zones. 5 TR 3653. While the Company has seen those localized improvements in the specific zones identified in Figure 26 at 4 TR 565, it takes time for these local benefits to materialize into systemwide benefits. See 4 TR 692. Given these local reliability improvements experienced, the Company is proposing to ramp up investments in Targeted Circuit Improvements to support an accelerated implementation of these benefits to the wider system.

Ms. Shi also stated that Staff could not find the differences between the bridge period and test year projects that would justify the increased test year spend. 5 TR 3653-3654. However, Mr. Lynd clearly explained in testimony that historic unit costs for Targeted Circuit Improvement projects vary widely, from $100,000 per project in 2020 and 2021 to less than $4,000 per project in 2022 and 2023. 4 TR 692-693. The lower costs in the more recent years are due to the Company performing a high number of lower cost fusing projects. 4 TR 693. But the fusing initiative is nearly complete, and there are fewer of these projects in the test year. See Exhibit A-127 (DAL-1),

pages 7 through 22 for the fusing projects in the bridge period, and Exhibit A-128 (DAL-2), pages 8 through 14 for the fusing projects in the test year. Instead, the Company will be completing additional large and complex projects in the test year, which means unit costs will again increase. 4 TR 693.

The Company provided substantial detail on its planned LVD projects in this case, with Exhibits A-127 (DAL-1) and A-128 (DAL-2) containing hundreds of individual projects with locations of the projects, projected costs, and expected benefits. 4 TR 693. Ms. Shi proposed a 35% reduction in the spending for these reliability projects without examining the merits of these projects. The Commission should reject Staff's proposed reduction in reliability improvements that has not fully considered the evidence provided by the Company in support of these investments. If Staff's disallowance for Targeted Circuit Improvements is adopted, the Company will have to delay many of its planned reliability projects, which will deny the associated reliability benefits to many communities in Michigan.

Staff witness Shi also recommended a reduction to ROW expenditures in the amounts of $800,000 in the bridge period and $4 million in the test year based on Staff's contention that the Company did not sufficiently support the projected spending. 5 TR 3656-3657. The Commission should also reject this reduction. The Company's proposed increase in LVD Lines Reliability investments will require additional ROW procurement prior to beginning these projects. 4 TR 695. The Company's projected increase from a five-year average of $4 million to a test year projection of $12 million is proportionally less than would be expected when considering the total increase in LVD Lines Reliability. *Id*. The Company's projection is reasonable and should be approved by the Commission.

MNSC witness Denzler also recommended reductions in the Company's planned reliability improvements. Mr. Denzler recommended that the Commission reject any increase in LVD Lines Reliability from 2023 levels, resulting in a disallowance of $344 million. 5 TR 3013. The Commission should reject this massive reduction in reliability investments and in the corresponding reliability benefits. Mr. Denzler argued that the Company's LVD Lines Reliability spending cannot be trusted because of his claims that (i) there is no evidence that these investments will improve reliability, (ii) there are alleged flaws in the Reliability Roadmap, (iii) the Company's RAE does not consider cost in prioritizing investments, (iv) the customer outage minutes avoided is not reliable, and (v) the Company is unreasonably planning to replace poles based only on age. See 5 TR 3006-3012. Mr. Denzler's argument should be rejected because they are inaccurate, fail to understand how the Company selects and prioritizes projects, and would deny the increased reliability benefits to customers throughout Michigan.

As an initial matter, see Section III.A.1of this Initial Brief for a response to Mr. Denzler's arguments regarding the Reliability Roadmap and the customer outage minutes avoided benefit. Mr. Denzler's criticism that the RAE does not consider cost fails to recognize that the Company does consider cost before performing reliability projects. The RAE is simply a tool that gathers many different types of data to create a zonal health score. 4 TR 698. The zonal health score helps to prioritize projects considering consistency of outages in the zone, outage rates per mile in the zone, customer impact of the outages in the zone, and the current 24-month outages in the zone. 4 TR 696-697. Thus, the zonal health score helps the Company identify those customers that are experiencing the poorest reliability, and prioritizes projects to improve that reliability. 4 TR 697.

Mr. Denzler argued that the Company should evaluate both the cost and benefit to "target resources where the biggest 'bang for the buck' can be realized." 5 TR 3009. Consumer Energy's

zonal health score and prioritization process is seeking the biggest "bang for the buck" – the Company identifies those areas that are experiencing the poorest reliability and seeks to address those areas as the best use of Company resources. 5 TR 697. If the Company were required to consider cost-benefit ratios before completing projects, it could result in certain customers experiencing poor reliability being passed over simply because the associated reliability projects do not meet a certain threshold. *Id*. The Company identifies the areas most in need of reliability improvements, and then uses a "least-cost-best-fit" analysis to select the appropriate solution. Least-cost-best-fit considers the goal sought to be achieved on the distribution system with the project and the lowest cost method for accomplishing that goal, and is commonly recognized in the industry as an appropriate way to evaluate reliability investments. *Id*.

Mr. Denzler also questioned the Company's decision to relocate the East Jordan line rather than just adopt a forestry solution and clear the line. 5 TR 3010. While clearing the East Jordan line might have offered a temporary solution to the reliability of the line, it is important to note that it also was a deteriorated line that would still be exposed to trees outside of the ROW that could easily fall on the line, break the conductor, and result in an outage to customers. 4 TR 698. While the Company agrees that line clearing provides reliability benefits, that does not mean that the Company should neglect the completion of other reliability projects that will harden the system and avoid outages that would occur even when the lines have been cleared. Indeed, while customers were experiencing three to four outages per year due to trees beginning in 2019, after the Company upgraded the two-phase conductor to tree wire in 2021, those customers experienced no interruptions from December 2021 through 2023. 4 TR 565. Mr. Denzler's concerns regarding this single project from 2021 do not support a disallowance of $344 million in reliability investments.

Mr. Denzler's understanding that the Company is planning to replace poles based only on age is incorrect. The Company will perform visual security inspections of poles and replace the most urgent poles identified from the pole inspection program. 4 TR 699. The Company plans to identify and replace all rejected poles on a 12-year pole inspection cycle, inspecting 125,000 primary and secondary poles each year. *Id*. While the Company uses data of pole age and historical rejection rates to estimate the total number of poles that will likely need to be replaced, poles are only replaced when they have actually been inspected and rejected. All poles that the Company has proposed for replacement in this case are poles that were inspected and rejected, and none are being replaced based on age. *Id*.

Mr. Denzler's drastic reduction in LVD Lines Reliability spending must be rejected. Mr. Denzler's criticisms of the Reliability Roadmap and the Company's benefits analysis is unfounded. Mr. Denzler's concerns with the Company's prioritization of projects fails to recognize that the Company reasonably selects reliability projects to address the areas that have the poorest reliability, and then reasonably fixes the problem using least-cost best-fit. Mr. Denzler's suggestion that the Company could have simply performed line clearing for the East Jordan project fails to recognize that line clearing alone is not sufficient to address all reliability concerns. And Mr. Denzler is incorrect that the Company is proposing to replace poles in this case based on age. The Company's proposed investments in LVD Lines Reliability should be approved to support the expected benefits in reliability for Consumer Energy's customers.

Attorney General witness Coppola stated his understanding that zonal health improvement projects represent a "new approach," and that the effectiveness of this approach should first be evaluated before the spending ramp up proposed in this case. 5 TR 2740-2741. Mr. Coppola recommended holding the projected test year spending to the same amount as the bridge period

plus inflation, resulting in a $178.189 million reduction in test year capital expenditures. 5 TR 2741. The Commission should reject this recommendation.

Zonal health improvement work is not a new or untested approach in this case. 4 TR 704. The Company has been performing zonal health improvements since 2013 as part of the Targeted Circuit Investments category, and provided information in this case indicating the proven benefits that the Company has experienced since 2018 in doing this work. 4 TR 565, 704. This is the first case to further explain the strategies included within Targeted Circuit Investments, which include zonal health improvements. 4 TR 704. But zonal health improvements are not new, and the Company's projected spending should not be reduced based on any misunderstanding that this is new and untested work in this case. Consumers Energy provided substantial detail on the type of work that is included in zonal health improvements (4 TR 562-567), and Exhibits A-127 (DAL-1), pages 4 through 23, and A-128 (DAL-2), pages 4 through 24, itemize all projected LVD Lines Reliability investment types and costs. 4 TR 705. The Commission should approve the requested spending to achieve the expected reliability benefits for customers.

Mr. Coppola also recommended reducing secondary conversions expenditures by $14.090 million based on his contention that the program only has a limited impact to few customers. 5 TR 2742. The Commission should reject this reduction. The average outage duration on secondary is more than 10 hours long, the system experiences an average of 10 secondary outages per day, secondary outages are more expensive for the Company to restore, and open-wire secondary disproportionately affects disadvantaged communities. 4 TR 706. Accordingly, the Company is planning to convert its open-wire secondary to multiplex secondary over a 10-year period, starting with circuits with the highest risk scores. 4 TR 568. Benefits of this initiative include improving safety by reducing the occurrence of difficult-to-repair wire downs, particularly

in EJ communities, and reducing the number of future upgrades that would be needed when customers adopt new technologies. 4 TR 568-569. While secondary issues are not a major contributor to systemwide SAIDI, these investments are necessary to address frequent and long-duration outages for a subset of customers. 4 TR 706.

Mr. Coppola also recommended keeping ROW expenditures to historical amounts, resulting in a proposed reduction of $2.859 million in the bridge period and $7.359 million in the test year. 5 TR 2743. For the same reasons discussed above in response to Staff witness Shi, the Commission should reject this recommended disallowance. 4 TR 707.

b) LVD Substations Reliability

References in the Record: Lynd, 4 TR 582-594, 707-710, Exhibits A-127 (DAL-1) and A-128 (DAL-2), A-251 (DAL-5); Coppola, 5 TR 2744-2747, Exhibit AG-1.7

The LVD Substations Reliability sub-program ensures the long-term safe and reliable operation of LVD substations, which are the interface between HVD lines and LVD lines, and reduces the risk of a customer experiencing a long duration outage. 4 TR 582-583. Projects include new or rebuilt substations, new mobile substations, animal mitigation, substation transformer replacements, and regulator replacements. 4 TR 583. The Company has identified that 6% of LVD substations are a high priority for repair or replacement, with another 23% identified as having a moderate level of risk. 4 TR 589. The Company's planned investment will address this risk, and is expected to result in two fewer LVD substation outages per year. *Id*. The Company targets areas for investment based on probability of future issues and to provide the greatest reliability improvements based on SAIDI and System Average Interruption Frequency Index ("SAIFI"). 4 TR 588.

Projected capital expenditures are $19.156 million in the bridge period and $43.725 million in the test year for LVD Substations Reliability. 4 TR 590. The projections were determined

based on the amount of investment needed to perform the planned projects, which are listed in Exhibits A-127 (DAL-1), page 24, and A-128 (DAL-2), pages 25-26. 4 TR 591. Benefits for the planned projects include expected reductions in customer outage minutes of 29,661,000 in the bridge period and 29,593,000 in the test year. 4 TR 593.

Attorney General witness Coppola argued that moving from an average of 4 substation rebuilds to 12 in the test year is excessive, and the unit cost is too high compared with the most recent three-year historical average. 5 TR 2745. Mr. Coppola recommended reducing the number of test year projects to 8 and reducing the unit cost, arriving at a proposed reduction of $14.410 million in the test year. *Id*. The Commission should reject this reduction.

First, the number of substation rebuilds should not be reduced in the test year. Consumers Energy has identified substations that are at risk, that need to be replaced or rebuilt, and the reliability benefits that will result from completing this work. See Exhibits A-127 (DAL-1), page 24, and A-128 (DAL-2), page 25. Rebuilding 12 substations in the test year is not "excessive," but is planned as part of the work needed to deliver the reliability benefits in the Reliability Roadmap.

Second, the Company's projected costs in the test year are not too high. Consumers Energy explained in discovery the reason for the increased unit costs in the test year. See Exhibit A-251 (DAL-5). The test year unit cost is higher primarily because of the different type of work being performed in the test year. The bridge period includes two substation rebuilds, continuing two new substations started in a previous period, two smaller scope projects, and seven property/easement purchases for future projects. 4 TR 708. In the test year, there are seven substation rebuilds, three new substations, including multi-mile HVD line construction for one substation, and two smaller scope rebuilt substation projects. *Id*. This difference in work scope

illustrates Company witness Lynd's explanation that "[a]verage unit cost is not a good measure to predict the cost of an individual project in the new or existing substation rebuilds . . . investment categor[y] due to specific work scopes needed for each project." 4 TR 593. New or rebuilt substation projects in the test year varied in cost from $230,000 to $2.409 million. 4 TR 709. Mr. Coppola's projection using an average historical unit cost should be rejected because it ignores these differing work scopes.

Mr. Coppola also recommended a reduction in Distribution Supervisory Control and Data Acquisition ("DSCADA") expenditures in the amount of $1.599 million in the bridge period and $1.88 million in the test year by applying a three-year average historical unit cost. 5 TR 2746-2747. The Commission should reject this funding reduction. While DSCADA unit costs are projected to increase, that is because the Company is installing DSCADA in more complex and difficult areas compared with previous years, which increases the costs of individual projects. 4 TR 709. DSCADA cost projections, like substation rebuilds, are determined based on the specific work scope for each project – average unit costs are not a good way to predict individual project costs. *Id*. DSCADA projects vary in the test year from $44,000 to $652,000. 4 TR 710, Exhibits A-127 (DAL-1), page 24, and A-128 (DAL-2), pages 25 and 26. The Commission should approve the Company's projections based on the unique scope of each of the planned projects.

c) LVD Repetitive Outages

References in the Record: Lynd, 4 TR 594-600, 710, Exhibits A-127 (DAL-1) and A-128 (DAL-2), Coppola, 5 TR 2747-2748

The LVD Repetitive Outages sub-program addresses areas of the distribution system that consistently experiences recurring customer interruptions, measured by Customers Experiencing Multiple Interruptions ("CEMI") inclusive of MEDs. Thus, this sub-program targets specific zones for improvements to address issues of frequent interruptions. 4 TR 594. Typical projects

include system protection upgrades, replacement of deteriorated or non-standard equipment, relocating portions of lines from dense trees or other poor access conditions, updating to tree wire in heavily wooded areas, and relocating overhead lines to underground. 4 TR 595. Targeting investment in the worst performing areas of the distribution system is expected to improve SAIDI, SAIFI, and CAIDI, which reduces both outage length and frequency. 4 TR 596. These proactive investments to replace deteriorated assets and reduce customer exposure to outages also improve employee and public safety and reduce the overall costs associated with the emergent response to additional interruptions. *Id*.

Projected capital expenditures are $11.538 million in the bridge period and $10.141 million in the test year for LVD Repetitive Outages. The projected expenditures represent the level of spending needed to complete 197 projects in the bridge period and 116 projects in the test year. 4 TR 598. Benefits for the identified projects are listed in Exhibits A-127 (DAL-1), pages 25 through 28, and A-128 (DAL-2), pages 27 through 28. 4 TR 598.

Attorney General witness Coppola recommended removing $5.409 million in the bridge period and $6.453 million for LVD Repetitive Outages based on using an average three-year historical project cost plus inflation. 5 TR 2748. The Commission should reject this reduction. In order to accomplish more significant CEMI improvements, the Company has shifted its investments within this sub-program to focus on more robust, but more costly, hardening projects such as line relocation, undergrounding, and replacing bare wire with tree resistant wire. 4 TR 599. The Commission should approve the Company's projection to reduce the number of repeat outages a customer experiences once poor performance is identified. 4 TR 600.

d) Metro Reliability

References in the Record: Lynd, 4 TR 600-608, Exhibits A-127 (DAL-1) and A-128 (DAL-2)

The Metro Reliability sub-program ensures the long-term safe and reliable operation of the Company's Metro systems through installation and upgrade of the civil and electrical assets that distribute electricity in downtown areas. Metro Reliability addresses obsolete or needed civil assets, obsolete or needed electrical assets, and dead fronting equipment. 4 TR 600. Projects are identified based on vault health scores. 4 TR 601. This sub-program improves overall reliability and operational safety, reduces overall cost associated with emergent response in the Metro Demand Failures sub-program, and reduces the likelihood of failure, resulting in fewer average minutes per year of outage. Benefits for the planned projects are identified in Exhibits A-127 (DAL-1), page 29, and A-128 (DAL-2), page 29. 4 TR 602.

Projected capital expenditures are $4.667 million in the bridge period and $4 million in the test year for Metro Reliability. 4 TR 606. The projections were determined based on the amount of investment needed to perform the planned projects. 4 TR 607.

e) LVD Substations Rehabilitation

References in the Record: Lynd, 4 TR 608-619, Exhibits A-127 (DAL-1) and A-128 (DAL-2)

The LVD Substations Rehabilitation sub-program includes the capital repair or replacement of LVD substation equipment that is at imminent risk of failure. 4 TR 608. The Company uses various means of inspection and analysis to identify locations to target for corrective action based on probability of an unplanned event and to provide the greatest reliability impact. 4 TR 609. Proactively replacing deteriorated equipment prior to an actual failure is more cost-effective because it typically avoids customer outages and overtime. *Id*. The benefits for the planned projects are identified in Exhibits A-127 (DAL-1), page 30, and A-128 (DAL-2), page 28,

and includes customer outage minutes avoided of 10,753,000 in the bridge period and 32,688,000 in the test year. 4 TR 614.

Projected capital expenditures are $13.595 million in the bridge period and $30.667 million in the test year for LVD Substations Rehabilitation. The projections are based on the amount of spending needed to complete the planned projects. 4 TR 616. The planned projects include replacement of Allis Chalmers substation transformers, remedying working clearance code issues, and replacement of deteriorating equipment. 4 TR 617.

f) LVD Lines Rehabilitation

References in the Record: Lynd, 4 TR 619-628, 710-711, Exhibits A-127 (DAL-1) and A-128 (DAL-2); Coppola, 5 TR 2749-2750

The LVD Lines Rehabilitation sub-program includes capital repair or replacement of LVD lines equipment assessed to be at risk of near-term failure and consists of imminent rehabilitation, subsurface transformer replacements, and the modem replacement program. 4 TR 619. The imminent rehabilitation category addresses situations where an actual failure has not occurred, but repair or replacement is required to prevent outages and the additional expenses associated with fixes performed after an asset failure. 4 TR 620. The modem replacement category replaces cellular modems installed inside control devices to address an announced end of support by the vendor in 2029. 4 TR 622. The subsurface transformer replacement category replaces original subsurface transformers that are difficult to access, that are not always recognized and avoided by the public, that are prone to leaking subterranean oil, and that result in outages that are about four times longer when they fail compared with padmount transformers. 4 TR 623. This sub-program reduces the likelihood of future actual failures and allows work to be completed in a more cost-effective manner. The benefits for the planned projects are identified in Exhibits A-127 (DAL-1), pages 33 through 39, and A-128 (DAL-2), pages 31 through 38. 4 TR 626.

Projected capital expenditures are $14.488 million in the bridge period and $15 million in the test year for LVD Lines Rehabilitation. 4 TR 623. The projected spending will enable the Company to complete the identified projects. 4 TR 624.

Attorney General witness Coppola argued that projected unit costs are too high and recommended reductions of $4.062 million in the bridge period and $5.405 million in the test year based on using a three year average historical unit cost plus inflation. 5 TR 2750. The proposed reduction should be rejected. Just as with many of the sub-programs already discussed in response to Mr. Coppola in this Initial Brief, Consumers Energy's cost projections are based on planned individual projects provided in Exhibits A-127 (DAL-1) and A-128 (DAL-2). 4 TR 711. There is a wide variance in the work required for LVD Lines Rehabilitation, ranging from $1,000 to $730,000 per project. Mr. Coppola's methodology of applying an average historical unit cost is unrealistic, does not account for the detailed support the Company provided for its cost projections based on the unique project costs, and should be rejected. 4 TR 711.

g) Metro Rehabilitation

References in the Record: Lynd, 4 TR 628-632, Exhibits A-127 (DAL-1) and A-128 (DAL-2)

The Metro Rehabilitation sub-program involves replacement of assets on the Metro system identified to be at a high risk of imminent failure to address risks to public safety, employee or contractor safety, and the reliability of the Metro system. This sub-program includes crushed duct replacement and vault or manhole rehabilitation. 4 TR 628. Performing these upgrades and replacements in the Metro system maintains a redundant system in the downtown areas of cities. 4 TR 629. Benefits for planned projects are identified in Exhibits A-127 (DAL-1), page 40, and A-128 (DAL-2), page 38. 4 TR 630. Projected capital expenditures are $7 million in the bridge

period and $6 million in the test year. 4 TR 631. The projections are based on the spending needed to complete the planned work. 4 TR 632.

h) Resiliency

References in the Record: Lynd, 4 TR 633-645, 711-717, Exhibits A-127 (DAL-1) and A-128 (DAL-2); Kelly, 5 TR 877-880, 1043-1045; Coppola, 5 TR 2750-2758, Exhibits AG-1.8 through AG-1.9

While much of the Reliability Roadmap focuses on improving reliability, the Resiliency sub-program focuses on enhancing resiliency by investing in system hardening to increase the distribution system's ability to withstand major storm events and recover from those events more quickly. 4 TR 633. The sub-program supports outage prevention and recovery, particularly during large events. *Id*. These additional resiliency projects are in response to worsening weather, including the increasing frequency of high-speed wind gusts over the past several years. 4 TR 634. The Resiliency sub-program will focus on fractionalization and overhead to underground conversions ("Undergrounding"). 4 TR 635.

Fractionalization involves segmenting LVD circuits into smaller sections with fewer customers, reducing the number of customers experiencing an outage for a single failure. 4 TR 635. Undergrounding will replace certain sections of overhead LVD line with underground lines and associated equipment and services to avoid outages caused by falling trees. 4 TR 638-639. The Resiliency sub-program spending is projected at $13.768 million in the bridge period and $22.623 million in the test year. 4 TR 640-641. This Resiliency spending will reduce the number of outages or the extent of the LVD system impacted during an outage. 4 TR 643.

Attorney General witness Coppola argued that some of the circuits that the Company identified for fractionalization "are not being fractionalized" or show "only minimal fractionalization," and contended that the Company has not shown a compelling case to target the listed circuits for fractionalization. 5 TR 2752-2753. Mr. Coppola recommended denying the full

$8.189 million in the bridge period and $12.623 million in the test year for fractionalization. 5 TR 2754. The recommended full disallowance of fractionalization costs should be rejected.

Although Mr. Coppola expressed concern that some of the circuits in Figure 72 of Mr. Lynd's Direct Testimony are not being fractionalized, Consumer Energy explained that Figure 72 shows every circuit on a given substation that will have any fractionalization work in the bridge period and test year, even if only some of the circuits on that substation are being fractionalized. 4 TR 712. Since the purpose of a fractionalization project is to reduce the number of circuits in the top tiers based upon customer count and overhead line exposure, a fractionalization project may not address every circuit in a substation. See Exhibit AG-1.8, page 4. This demonstrates that the Company is reasonably selecting the most impactful circuits for fractionalization, and certainly is not a reason to disallow all fractionalization costs.

Mr. Coppola further argued that the Company's statement in discovery that fractionalization projects do not result in an overall reduction in outage incidents does not show a compelling case for the planned fractionalization investments. 5 TR 2753. But that discovery response only makes clear the purpose of fractionalization, which is to reduce the number of customers that experience a given outage when an outage does occur. 4 TR 713. The planned fractionalization projects and projected benefits are shown in Exhibits A-127 (DAL-1), page 41, and A-128 (DAL-2), page 40.

In Case No. U-21389, the Commission approved the Company's proposed fractionalization work as part of the Resiliency program in the Investment Recovery Mechanism ("IRM"), and the test year in that case is the last 12 months of the bridge period in this case. 4 TR 712-713; Case No. U-21389, March 1, 2024 Order, pages 272-273. The Commission should continue to approve

the Company's fractionalization as reasonable and prudent to reduce the number of customers that are affected by outages.

Mr. Coppola also recommended that the Commission deny any expansion of the Undergrounding program, which would reduce expenditures by $1.879 million in the bridge period and $10 million in the test year. 5 TR 2758. Mr. Coppola argued that the project selection thresholds were relatively low, project selection does not include a cost benefit analysis, costs for Undergrounding the 3,200 miles that are candidates would be too high, the $400,000 per mile projected cost does not seem realistic, Undergrounding is more expensive than other options, and it is premature to expand the previously approved pilot. 5 TR 2755-2757. The Commission should reject these arguments and any reduction in Undergrounding costs.

The Company's selection criteria has not changed from when the pilot program was approved by the Commission. 4 TR 714. The selected zones must be single phase, had at least one outage in the last 24 months, serve between 10 and 100 customers, be operated at one of the three standard wye voltages, not under consideration for another reliability project, have an average CAIDI of 600 minutes or more, have a load after installation of 36% or less of the ampacity of newly installed facilities, be located in dense trees, and not supply an overhead system. 4 TR 639. These criteria identify zones where the Undergrounding projects will be more cost-effective, provide an immediate reliability benefit to more than a few customers, avoid duplication of reliability efforts, avoid replacing the facilities before end-of-life, minimize forestry clearing costs, and facilitate timely restoration. 4 TR 640.

These criteria are used to select certain portions of the system that are good candidates for Undergrounding projects. 4 TR 715. However, the Company will consider other factors before determining to move forward with a project, including physical barriers to construction that could

significantly increase costs. Exhibit AG-1.9, page 3. No additional cost-benefit analysis is needed for these projects as long as the projects are consistent with the selection criteria, which include the projects presented in this case. 4 TR 715. The Company's projections in this case include a specific number of miles proposed to be converted from overhead to underground in specific locations, identified in Exhibits A-127 (DAL-1), page 41, and A-128 (DAL-2), page 40. 4 TR 715.

As to Mr. Coppola's concerns that the cost of Undergrounding 3,200 miles would be too high, that Company has not asserted, and is certainly not proposing in this case, to complete all 3,200 miles of Undergrounding. 4 TR 715. While the 3,200 miles represents areas of the system that have the potential for Undergrounding, the Company is only requesting approval of the investments through the test year in this case, which represent about 39 total miles in the bridge period and test year. And while Mr. Coppola argued that the Company's $400,000 per mile projection does not seem realistic, the Company referred to data indicating both higher and lower per mile costs in developing this projection. 4 TR 716-717; Exhibit AG-1.9, pages 1-2. The Company is working to create efficiencies and lower unit costs in this program, including limiting the scope to single-phase installations. 4 TR 717.

The Company is ramping up Undergrounding in this case to deliver reliability and resiliency benefits for customers. And of the 25 miles of Undergrounding planned in the test year, 5 miles are in EJ communities. 5 TR 879. The Company expects an improvement in reliability of 90% or more from Undergrounding. 5 TR 880. While Mr. Coppola is correct that Undergrounding costs 9% to 12% more than alternatives such as Aerial Spacer Cable and Tree Wire, this is a small increase for the reliability gains from approximately 64% for the alternatives to more than 90% for Undergrounding. 5 TR 1044.

It is not premature for the Commission to approve additional miles of Undergrounding in this case. The intent of the Undergrounding pilot approved in Case No. U-21389 is to confirm the costs of Undergrounding compared with other alternatives and to track the SAIDI improvements gained from Undergrounding. 5 TR 1044. Undergrounding is a well-understood strategy in the industry to improve reliability and resiliency, and not a novel technology with unknown real-world results. 5 TR 1045. The Company identified circuits where burying lines will benefit customers by greatly improving their reliability, and the Company has developed an Undergrounding workforce that is prepared to continue executing Undergrounding projects. *Id*. The Commission should approve the Company's projected Undergrounding expenditures to enable the Company to deliver these benefits to customers.

v. LVD Capacity

References in the Record: Lynd, 4 TR 645-673, Exhibits A-127 (DAL-1) and A-128 (DAL-2)

The Capacity Program ensures that the distribution system can serve the electric peak demand, keep the system within acceptable voltage ranges, and support the Company's Conservation Voltage Reduction ("CVR") Program. LVD includes LVD Lines Capacity, LVD Substations Capacity, LVD Transformers Capacity, LVD New Business Capacity, and CVR. 4 TR 645-646.

a) LVD Lines Capacity

References in the Record: Lynd, 4 TR 647-657, 717-719, 721-722, Exhibits A-127 (DAL-1) and A-128 (DAL-2); Coppola, 5 TR 2758-2762; Jester, 5 TR 3119-3120

The LVD Lines Capacity sub-program is designed to address and reduce overload risk on the LVD system because overloads that are too long or too frequent lead to deterioration and increased risk of failure. 4 TR 647. Investments in this sub-program respond to overload risks that already exist due to load growth or load shifting and ensure that the LVD system can

accommodate projected distribution loads. 4 TR 647. This sub-program includes investments in equipment upgrades and lines capacity projects associated with substation projects. *Id*. The investments projected in this case are to address a backlog of known issues where assets are loaded to greater than 100% of their rating. 4 TR 648. The identified projects in this sub-program are listed in Exhibits A-127 (DAL-1), page 42, and A-128 (DAL-2), pages 41 through 47. 4 TR 655-656. Projected capital expenditures are $19.082 million in the bridge period and $56.723 million in the test year for LVD Lines Capacity. 5 TR 2018. The projected expenditures represent the spending needed to perform the identified projects. 4 TR 655-656.

Mr. Coppola argued that the Overload Equipment unit cost and the test year number of projects are too high compared with the historical average, and recommended a $3.913 million reduction in the bridge period and a $32.755 million reduction in the test year. 5 TR 2759-2761. The Commission should reject this recommended reduction. Mr. Coppola's methodology of applying an average unit cost to the bridge period is unreasonable because it ignores that individual project costs in this investment category vary widely based on scope and complexity. 4 TR 717-718. The Company developed projected costs specific to each project in this category, which were used to project the bridge period capital investment as itemized in Exhibit A-127 (DAL-1), page 42. 4 TR 718. This is illustrated by the fact that applying a unit cost analysis to the test year projects and investments, which are again based on the costs of the actual projects proposed, would result in a test year unit cost of $139,609, which is lower than Mr. Coppola's proposed $143,301 unit cost based on a historical average plus inflation. 4 TR 718. Mr. Coppola's unit cost approach must be rejected.

As to Mr. Coppola's proposed reduction in the number of Overload Equipment projects in the test year, the Company performed a comprehensive review of the system to quantify all

overloaded assets on the system. The Company is presenting a plan in this case to address these overloads. 4 TR 718. If the Company only completes 90 projects in the test year as Mr. Coppola proposes, it will result in overloaded assets remaining on the system for longer, which increases the risk of overload-related outages. *Id*. The Commission should avoid this result by approving the Company's projected expenditures.

Mr. Coppola also recommended a reduction to Lines Capacity Projects Associated with Substation Work in the amount of $9.572 million in the bridge period and $4.959 million in the test year by applying a three-year historical average plus inflation. 5 TR 2762. The Commission should also reject this reduction. Similar to Mr. Coppola's other proposed reductions based on unit costs, using unit costs to project expenditures in this category is not reasonable because there is a wide variance in the cost of the work required. 4 TR 657, 719. The Company set projected expenditures based on the specific and discrete projects that were identified in Exhibits A-127 (DAL-1), page 42, and A-128 (DAL-2), page 47. 4 TR 719. As illustrated in these exhibits, there is a wide range of costs for the individual projects – the Commission should approve the Company's detailed cost projections based on those individual project costs. *Id*.

MNSC witness Douglas B. Jester recommended that the Commission require the Company to undertake a thorough consideration of EV charging in its next distribution system plan and propose an approach to most cost-effectively meet the needs for EV charging. 5 TR 3120. Consumers Energy would support performing additional studies regarding the future of EV adoption, but notes that the study discussed in this case of the 17 high-propensity circuits involved a significant effort with manual intervention to perform the analysis in the Company's current software. 4 TR 722. The analyses that Mr. Jester proposed could be more easily accomplished using the Load Flow Tool Upgrade that the Company has proposed in this case. 4 TR 722; see

Section III.A.1.c of this Initial Brief. If the Commission agrees that it would like the Company to perform additional EV charging analyses, the Commission should also approve the Load Flow Tool Upgrade to assist the Company in responding to Mr. Jester's suggestions and other collaborative efforts. 4 TR 722.

b) LVD Substations Capacity

References in the Record: Lynd, 4 TR 657-662, Exhibits A-127 (DAL-1) and A-128 (DAL-2)

The LVD Substations Capacity sub-program ensures the long-term safe and reliable operation of the Company's LVD substations by installing new substations or substation equipment and upgrading existing substations to meet customer electric loads. 4 TR 657. This sub-program prevents future system overloads and addresses existing overloads, which would eventually result in equipment failure and customer outages, and ensures that the Company has adequate capacity on the distribution system to serve customer load. 4 TR 658. The number of customers benefitting from each project in this sub-program are identified in Exhibits A-127 (DAL-1), page 43, and A-128 (DAL-2), page 48. Projected capital expenditures are $27.777 million in the bridge period and $22.27 million in the test year for LVD Substations Capacity. 4 TR 660. The projections are based on the Company's identified capacity needs and planned projects to address those needs. 4 TR 660-661.

c) LVD New Business Capacity

References in the Record: Lynd, 4 TR 662-667, Exhibit A-127 (DAL-1)

Projects in the LVD New Business Capacity sub-program are driven by customer requests and are generally similar in scope to projects in the LVD Lines Capacity sub-program. 4 TR 662. Work in this sub-program supports the reliable distribution of electricity to customers by preventing overloads on the system that can cause outages and poor voltage service, and includes

the added benefit of allowing customers to expand their activities and drive economic growth in Michigan. 4 TR 663. Projected capital expenditures are $23.903 million in the bridge period and $20.319 million in the test year. 4 TR 664. The projected expenditures are based on historical actual spending with adjustments for observed trends. 5 TR 2029.

d) Conservation Voltage Reduction

References in the Record: Lynd, 4 TR 667-673, Exhibits A-127 (DAL-1) and A-128 (DAL-2)

CVR provides the ability to optimize voltages at the customer meter to reduce energy demand without requiring the customer to actively participate. 4 TR 667. CVR technologies reduce the delivery voltage along LVD circuits, which reduces the amount of electric load that must be served on the circuit. The technology optimizes control settings on substation and downstream voltage equipment, and allows for continuous monitoring and automatic adjustment of these settings to achieve optimal voltage and load reduction. 4 TR 667. CVR was included and approved by the Commission in the Company's Integrated Resource Plans ("IRP") in Case Nos. U-20165 and U-21090. *Id*. Projected capital expenditures are $4.609 million in the bridge period and $3.343 million in the test year. 4 TR 670. The spending in this sub-program is designed to implement the Company's CVR plan as approved by the Commission in Case No. U-21090. 4 TR 671.

vi. Wildfire Risk Mitigation

References in the Record: Kelly, 5 TR 871-876, 1045-1048, 1053-1054, Exhibits A-114 (MPK-22) and A-246 (MPK-30); Exhibit A-128 (DAL-2); Coppola, 5 TR 2764-2767, Exhibit AG-1.11; York, 5 TR 3357-3359

As part of the development of the Reliability Roadmap, the Company analyzed several potential risks associated with the distribution system, including wildfires. Recent wildfires in Northern Michigan, Hawaii, and Texas highlight the threat posed by wildfires. 5 TR 872.

According to the Federal Emergency Management Agency ("FEMA"), approximately 21% of the Company's service territory is in areas with elevated wildfire risk, primarily in the north central Lower Peninsula. 5 TR 873-874. The Company is proposing a program to mitigate this wildfire risk and has included its Wildfire Risk Mitigation Plan as Exhibit A-114 (MPK-22). 5 TR 872.

In developing the program, the Company consulted with several utilities and researched other utilities' publicly available wildfire risk mitigation plans. 5 TR 872. Based on this research, the Company found that there are generally four types of risk mitigation: (1) situational awareness, which includes wildfire weather forecasting, enhanced inspections, risk modeling, fire detection cameras, and fire spread modeling; (2) operational procedures, which includes modified field operating procedures, modified recloser settings, public safety power shutoff, and emergency preparedness; (3) system hardening, which includes sectionalizing devices, covered conductor, Undergrounding, and building microgrids; and (4) vegetation management, which includes the expansion of scope and frequency of line clearing. 5 TR 873.

The Company's proposed Wildfire Risk Mitigation investments planned through 2028 will:

- Support situational awareness through risk assessment, weather monitoring, and enhanced inspections;
- Develop operational procedures to reduce the risk of ignition during periods of elevated wildfire risk and implement an emergency response in the event of a wildfire hazard;
- Perform targeted system hardening, including moving high-risk overhead conductor underground, installing conductor with a polymer sheath on high-risk circuits, and increasing sectionalization by adding Supervisory Control and Data Acquisition ("SCADA")-enabled devices; and
- Reduce the cycle time for line clearing to a five-year average for 7.2/12.47 kV and 4.8/8.32 kV circuits in elevated wildfire risk areas, using Light Detection and Ranging ("LiDAR") to prioritize the circuit sequence for this reduction in cycle times. 5 TR 875-876.

The Company is projecting $12 million in test year capital expenditures for Wildfire Risk Mitigation, with $4 million for Undergrounding, $4 million for covered conductor, and $4 million for protective line devices. Exhibit A-128 (DAL-2), page 51, indicates the planned projects and projected project expenditures. The Company is also projecting $652,000 of O&M in the test year for the program, with $12,000 for wildfire-specific weather forecasting, $321,000 for increased line clearing to reduce the clearing cycle, and $319,000 for LiDAR. 5 TR 876. The Commission should approve the Company's Wildfire Risk Mitigation costs in this case to support the Company's efforts to mitigate the risk of wildfires in its service territory and protect public safety, physical structures, the environment, and the electric distribution system. See Exhibit A-114 (MPK-22), page 30.

Attorney General witness Coppola recommended complete rejection of the $12 million in Wildfire Risk Mitigation expenditures, arguing that the risk of electric lines wildfires in the Company's service territory is minimal. 5 TR 2765, 2767. Similarly, ABATE witness York recommended the rejection of these expenditures because of her contention that the Company did not explain why its normal operating procedures are not sufficient. 5 TR 3358-3359. The Commission should reject the removal of the Wildfire Risk Mitigation expenditures.

The Company's proposed Wildfire Risk Mitigation Plan is based on FEMA's wildfire risk assessment that identifies the risk of wildfire in certain census tracts in Michigan as "Relatively High." 5 TR 1046. The area surrounding Lahaina, Hawaii also has a "Relatively High" risk rating by FEMA, and that area experienced a devasting utility-related wildfire on August 8, 2023 where 100 lives were lost, 2,200 structures were destroyed, and $5.5 billion worth of property was damaged. 5 TR 1046. Consumers Energy's Wildfire Risk Mitigation Program is a reasonable proposal to mitigate this "Relatively High" risk of wildfire in its service territory. *Id*.

Mr. Coppola expressed concern that the $12 million requested in this case was only the beginning of expenditures that will continue to grow. 5 TR 2767. The Company is only requesting approval of the $12 million in capital (as well as associated O&M) in the test year in this case. While the Company provided its five-year plan in Exhibit A-114 (MPK-22), the Company will continue to evolve and improve the plan based on continual review of the wildfire risk in Michigan, any new risk reduction strategies or technologies, changing weather patterns, and consultation with industry experts and peers. 5 TR 1047.

Mr. Coppola also contended that wildfires that do occur in Michigan are "usually easily contained and do not pose a large risk to the state's population." 5 TR 2766. But even small and "easily contained" fires can result in evacuations, property damage or loss, and injuries, as well as require multi-agency responses. 5 TR 1047. And climate change is expected to increase the hazards posed to the Company's distribution assets from wildfires. 5 TR 1048. The Company's proactive proposals in this case will allow the Company to implement measures to mitigate the potential for wildfires, reduce the impact of wildfires when they do occur, and maintain a resilient electric grid. *Id*. The Commission should reject the Attorney General's suggestion to ignore the risk of wildfires in the Company's service territory.

While the Company has developed and implemented operational procedures and situational awareness that will help to mitigate wildfire risk, best practices to reduce this risk also include system hardening and line clearing. 5 TR 1054. And while the Company performs similar types of work in other distribution programs, the work in the Wildfire Risk Mitigation Program is targeted to those areas with an elevated wildfire risk. *Id*. The Commission should approve the proposed Wildfire Risk Mitigation expenditures to mitigate the risk of wildfires for the Company's customers.

vii. Metering and Transformers

a) LVD Metering

References in the Record: Lynd, 4 TR 673-680; Kelly, 5 TR 1054-1055, Exhibit A-111 (MPK-19); Sherman 5 TR 3173-3197, Exhibits MEUI-12 through MEIU-13

The LVD Metering sub-program supplies meter sockets, metering transformers, and meter test equipment. 4 TR 673. Metering is an essential part of the broader requirement to connect new customers and to replace failed equipment. 4 TR 674. The LVD Metering sub-program also maintains metering accuracy by replacing meters that are nonfunctional, damaged, or where accuracy has been questioned by the customer. *Id.* Projected capital expenditures are $52.024 million in the bridge period and $45.494 million in the test year. 4 TR 675. Cost projections are based on the projected activity in the New Business and Demand Failures sub-programs, which is based on historical data and forecasts of future new business connections and large project work. 4 TR 675.

MEUI witness Dr. Laura S. Sherman recommended that the Commission open a standalone docket to evaluate desired next-generation Advanced Metering Infrastructure ("AMI") functionality and vendor capabilities, develop a business case, and execute a procurement and implementation strategy that maximizes potential benefits. 5 TR 3197. In the Reliability Roadmap, the Company discussed the plan to begin replacing 4G LTE meters with 4G CatM1 or 5G meters, beginning with 50,000 per year and ramping up to 175,000 per year from 2027 through 2032. Exhibit A-111 (MPK-19), page 97. Since the Reliability Roadmap was filed, the Company learned that 4G technology is now planned to be supported into the mid- to late-2030s, which is more time than the projected end date of 2032 in the Reliability Roadmap. 5 TR 1055, Exhibit A-111 (MPK-19), page 96. Because of this change in schedule, the Company is not planning to

begin upgrading 4G meters until at least 2028 or 2029. 5 TR 1055. Thus, there is no need for the Commission to require a new proceeding related to AMI replacement.

b) LVD Transformers

References in the Record: Lynd, 4 TR 680-685

The LVD Transformers sub-program supplies the distribution transformers to provide electricity to customers at an acceptable voltage, with the number of transformers needed primarily driven by the LVD Lines New Business sub-program. 4 TR 680. Projected capital expenditures are $71.336 million in the bridge period and $75.583 million in the test year. 4 TR 681. The distribution transformer purchase plan is developed based on historical actual data, taking into account potential fluctuations based on lines projects in the Company's reactive spending programs. 4 TR 682.

viii LVD Project Expenditures Are Not Premature

References in the Record: Lynd, 4 TR 719-721; Coppola, 5 TR 2763-2764, Exhibit AG-1.10

Attorney General witness Coppola identified 8 projects in the bridge period and 26 projects in the test year that are in the planning phase or that have been deferred, and recommended removal of the costs of these projects. 5 TR 2763-2764. To avoid duplication, Mr. Coppola removed the cost of 12 of the projects from the reduction because those projects were in programs where Mr. Coppola had already proposed other reductions. 5 TR 2764. The total recommended disallowance is $14.428 million in the bridge period and $14.144 million in the test year. 5 TR 2763-2764. The Commission should reject these proposed reductions.

Mr. Coppola is incorrect to assume that projects in the planning phase of development are in any way uncertain. The Company provided expected construction start and completion dates for these projects, and the Company fully plans to complete these projects by the stated dates.

4 TR 720. There is no evidence to support a conclusion that the Company is unlikely to perform these projects. And even for deferred projects, which only total $2.3 million of the Attorney General's recommended disallowance of $28.5 million, the Company has incorporated other projects into its workplan, including higher priority zonal health work, so that the total projected expenditures have not changed and should be approved by the Commission. 4 TR 720-721; Exhibit AG-1.10.

d. Grid Modernization

References in the Record: McPhail, 5 TR 2201-2298, Exhibits A-132 (SAM-1) through A-139 (SAM-8)

Grid Modernization is the planned process of investing in grid infrastructure improvements, and incorporating new technologies and applications into the electric system to increase reliability. 5 TR 2204. The Company's targeted Grid Modernization investments will improve reliability and resiliency, reduce power quality issues and system losses, reduce capital and maintenance costs, increase asset availability, and reduce asset degradation risk. 5 TR 2204-2205. After performing an independent review, the EPRI found that the Company's Grid Modernization plan is in line with industry practices. 5 TR 2208; see Exhibit A-134 (SAM-3). As discussed below, Grid Modernization investments are grouped into five areas of work: Distribution Circuit Modernization, Substation Modernization, Distribution Asset Management, Planning Systems Modernization, and Operational Systems Modernization. Total projected Grid Modernization investments are $24.258 million in the bridge period and $37.689 million in the test year. 5 TR 2210-2211.

i. Distribution Circuit Modernization

References in the Record: McPhail, 5 TR 2212-2248, 2293; Coppola, 5 TR 2778-2779

Distribution Circuit Modernization is an initiative that involves research, development, and demonstration of future technologies and solutions that improve reliability and resiliency on the LVD system. 5 TR 2212. This initiative includes three deployment projects and five Technology Enablement Process initiatives. *Id*. The deployment projects are Line Sensors, Voltage Regulator Controllers, and Capacitor Upgrades.

Line Sensors are installed on the overhead primary conductor to monitor electrical current and detect actual and potential faults. 5 TR 2216. The monitoring capability and use of real-time data reduce unscheduled outage durations by providing more awareness during outage response, and provide monitoring capability of equipment that may be nearing its rated capacity. 5 TR 2217. Voltage regulators adjust voltage on the distribution system based on changing load conditions, and voltage regulator controllers are connected through the Advanced Distribution Management System ("ADMS") to provide dynamic remote-control and monitoring capabilities. 5 TR 2222. This capability ensures the Company is providing the appropriate voltage to customers and is necessary to support the Company's CVR objectives. 5 TR 2223. Capacitor Upgrades involve the installation of neutral current sensors on capacitor banks to provide remote monitoring capabilities that detect imbalances and result in improved power quality for customers. 5 TR 2228. Imbalances could damage and diminish the lifespan of the equipment on the system, resulting in premature equipment failures and reduced reliability. 5 TR 2228-2229. Imbalances could also reduce the voltage reduction capabilities achieved through the CVR program. 5 TR 2229. This remote monitoring allows the Company to more quickly identity issues, reduce the time to dispatch a crew for repairs, and avoid field inspection of capacitors. *Id*.

The Technology Enablement Process initiatives are NOVA Triple-Single Recloser Communications, Peer to Peer Automation Scheme, Recloser Modernization, Line Sensor Alternatives, and Metro Modernization. Under the Technology Enablement Process, these technologies will be worked through defined phases from planning to grid integration, which can include use case development, small scale lab testing, field testing, and field implementation. 5 TR 2213. The Company also performs operations training, process alignment workshops, and identifies change management benefits, with projects selected based on their ability to provide customer benefits, advance the distribution grid, and promote future technologies. *Id*.

Projected Distribution Circuit Modernization expenditures are $16.973 million in the bridge period and $16.095 million in the test year.

Attorney General witness Coppola recommended a reduction in the capital expenditures for line sensors in the amount of $1.675 million in the bridge period and $4.266 million in the test year by using a three-year historical average unit cost plus inflation. 5 TR 2779. The Commission should reject this reduction. Project costs in this investment category can span multiple years, and the variance in timing of material deliveries can result in two years of material being charged in one calendar year. 5 TR 2221. The material accounts for over 75% of the total program cost, and thus taking an annual cost and dividing it by the annual units completed is not an effective method for understanding unit cost. *Id*. Instead, the Company projects line sensor expenditures by calculating unit costs based on historical data, contracted labor, and material costs across all of the planned projects with calendar year spend. *Id*. The test year costs also includes renewal of software necessary to provide data from the line sensors to the Company's ADMS. 5 TR 2292.

The Company's projected unit cost more precisely considers all the factors that will contribute to the unit cost in the bridge period and test year that make up the unit cost, and should

be approved as the amount needed for the installation costs of each line sensor and the software renewal. 5 TR 2292. The Company does propose to reduce the bridge period expenditures for line sensors by $2.083 million because Reliability Analytics Monitoring Program ("RAMP") expenditures were mistakenly included with both line sensors and under Planning Systems Modernization. 5 TR 2293.

ii. Substation Modernization

References in the Record: McPhail, 5 TR 2248-2260

Substation Modernization includes researching, developing, and demonstrating desired future state advanced distribution substation technologies. 5 TR 2248. These technologies enable current and future initiatives such as Distribution Circuit Modernization, ADMS, and the increased penetration of DERs. *Id*. This initiative identifies and prioritizes solutions that provide adaptability, interoperability, security, resiliency, and reliability to grid operations to support the grid of the future. *Id*. Projected expenditures are $682,000 in the test year.

iii. Electric Distribution Asset Management

References in the Record: McPhail, 5 TR 2260-2273, 2293-2294; Coppola, 5 TR 2780-2781, Exhibit AG-1.14

Electric Distribution Asset Management ("DistAM") develops lifecycle management capabilities by collecting key assets (such as age, nameplate data, and location) to support the Company in making risk-informed decisions to manage and optimize asset investments. 5 TR 2260. DistAM will collect distribution asset data into a single centralized database that will provide enhanced integration into asset health performance, and is aligned with industry best practices defined in ISO 55000(1) and the Michigan Infrastructure Council Asset Management Program. 5 TR 2260-2261. Investment categories include asset repository, asset performance

management, and asset investment planning, with total projected expenditures of $5.9 million in the bridge period and $6.863 million in the test year. 5 TR 2262.

Mr. Coppola recommended disallowance of all DistAM expenditures (as well as all Planning Systems Modernization and Operational Systems Modernization) in the bridge period and test year. 5 TR 2780-2781. Mr. Coppola generally argued that these expenditures could be directed toward "more immediate needs" and that the Company has not shown that the new systems are necessary. 5 TR 2780. Mr. Coppola's recommendation fails to adequately consider the support that the Company provided for these programs and the benefits they will provide, and the rejection of the entirety of this funding should be rejected by the Commission.

Consumers Energy witness Scott A. McPhail provided extensive support in testimony for the DistAM project. See 5 TR 2260-2273. The project includes the Asset Repository, which provides a single centralized database to store essential distribution asset data and enhances the Company's ability to proactively monitor and replace assets prior to an outage. 5 TR 2263, 2266. Asset Performance Management provides for data capture, integration, visualization, and analytics to improve the reliability and availability of physical assets, improving the Company's processes for calculating and visualizing asset health to ensure the most critical projects are prioritized. 5 TR 2266, 2268. Asset Investment Planning uses data stored within the Asset Repository and health index scores within Asset Performance Management to make data-driven decisions regarding capital investments, maintenance costs, criticality of budgets and associated risk, and analysis to plan where and when to invest, improving the Company's processes for prioritizing work with the greatest return on investment. 5 TR 2269, 2271.

Consumers Energy fully supported the benefits of the DistAM project, which supports the use of data and analytics to inform long-term investment decisions and continuous improvement

of electric distribution system operations. 5 TR 2271. DistAM provides the tools needed to measure, understand, and evaluate asset data, and integrate that data across resources. 5 TR 2272. Without an effective asset management program in place, asset lifecycle information would be lacking, reducing the effectiveness of the distribution system. *Id*. In addition to the EPRI report stating that Consumers Energy's Grid Modernization initiatives should be considered standard, or leading, industry practice, the independent, third-party audit recently conducted as part of Case No. U-21305 concluded that DistAM as proposed in the Reliability Roadmap will enhance asset management. 5 TR 2294.

Mr. Coppola's generalized criticisms of DistAM should be rejected because they fail to address the numerous asset management benefits that DistAM will provide.

iv. Planning Systems Modernization

References in the Record: McPhail, 5 TR 2273-2280, 2293-2294; Coppola, 5 TR 2780-2781, Exhibit AG-1.14

Planning Systems Modernization involves researching, developing, and demonstrating desired future state technologies and solutions to integrate into the Company's planning framework. 5 TR 2273. The goal of this initiative is to support a planning approach that assesses physical and operational changes to the electric distribution grid needed to enable safe, reliable, resilience, and affordable service that meets customers' expectations and the use of DERs. 5 TR 2274. This initiative involves evaluating the existing landscape of planning tools and processes to identify opportunities to use new technologies, improve efficiency, and prepare for the modern grid of the future. *Id*. Investment categories include the RAMP, Load Flow Tool Upgrade, and Grid Modernization Analytics, with total projected expenditures of $687,000 in the bridge period and $4.916 million in the test year. 5 TR 2275.

As discussed above, Mr. Coppola generally recommended disallowance of all Planning Systems Modernization expenditures (as well as all DistAM and Operational Systems Modernization) in the bridge period and test year. 5 TR 2780-2781. For the same reasons discussed above, Mr. Coppola's recommendation fails to adequately consider the support that the Company provided and should be rejected by the Commission.

Consumers Energy witness McPhail provided extensive support in testimony for Planning Systems Modernization. See 5 TR 2273-2280. RAMP analyzes waveforms and data from the existing line sensors, along with outage ticket data, to build correlations between specific sensor waveform signatures and outage cause codes, as well as predictive models that further enhance a line sensor's capability of identifying power delivery issues beyond fault detection. 5 TR 2275. RAMP will proactively identify disturbances on the electric distribution system and avoid customer outages. 5 TR 2277. The Low Flow Tool Upgrade will enhance the Company's capability for modeling the LVD system, including advanced capabilities for forecasting, modeling, and simulating DER and EV. 5 TR 2277. This tool will reduce equipment failure resulting from overload, undervoltage, or other abnormal conditions because it allows for more granular and accurate studies, while also supporting the Company's approach for improving hosting capacity in EJ communities. 5 TR 2278. Grid Modernization Analytics will develop advanced analytics to provide increased visibility into the electric distribution system, identifying opportunities for efficiencies and better direction for the Company to use when making decisions involving future use cases and customer benefits. 5 TR 2279.

The Commission should support the Company's investment in a modern distribution planning system to promote the Company's ability to proactively monitor and analyze data on the electric distribution system in preparation for load growth and impacts from DERs and EVs. 5 TR

2280. Planning Systems Modernization will support the Company's ability to strengthen and upgrade targeted areas of the distribution system before they result in customer outages. *Id*. Mr. Coppola's generalized criticisms of Planning Systems Modernization should be rejected because they fail to address the numerous benefits that Planning Systems Modernization will provide.

v. Operational Systems Modernization

References in the Record: McPhail, 5 TR 2281-2288, 2293-2294; Coppola, 5 TR 2780-2781, Exhibit AG-1.14; Albers, 5 TR 3206-3231, 3234, Exhibits MEIU-15 through MEIU-21; Kenworthy, 5 TR 2664-2669

Operational Systems Modernization involves researching, developing, and demonstrating desired future state technologies and solutions to integrate into the Company's operational processes. 5 TR 2281. This initiative seeks to identify improvements and future state requirements for the electric business's operation steps and processes. This initiative is currently focused on the planning and implementation of a modern Fault Location, Isolation, and Service Restoration ("FLISR") program. *Id*. FLISR is an ADMS application that uses communicating grid equipment, such as line sensors and reclosers, to quickly detect and locate where faults are on the system and then automatically re-route power to minimize the number of customers impacted. 5 TR 2282.

Operational Systems Modernization also includes DER Optimization, which lays the groundwork for incorporating a standardized methodology to deliver capabilities such as modeling, monitoring, operating, and coordinating DERs in order to optimize and safely integrate them into the electric distribution system. 5 TR 2284-2285. This will involve the evaluation of DER management capabilities through the implementation of a DER Management System ("DERMS"). 5 TR 2285. The Company is planning to conduct benchmarking and learning sessions with stakeholders and engage a consultant to formalize a business case and deployment strategy, ensuring a safe and reliable electric distribution system considering the requirement of

Federal Energy Regulatory Commission ("FERC") Order 2222 and the 2023 energy law in Michigan. *Id*.

Total projected Operational Systems Modernization expenditures are $698,000 in the bridge period and $9.133 million in the test year.

As discussed above, Mr. Coppola generally recommended disallowance of all Operational Systems Modernization expenditures (as well as all DistAM and Planning System Modernization) in the bridge period and test year. 5 TR 2780-2781. For the same reasons discussed above, Mr. Coppola's recommendation fails to adequately consider the support that the Company provided and should be rejected by the Commission.

Consumers Energy witness McPhail provided extensive support in testimony for Operational Systems Modernization. See 5 TR 2281-2288. FLISR will revolutionize the management of electric outages by rerouting power to minimize their impact and duration and by quicker fault detection to shorten outages. 5 TR 2284. DER Optimization, and the research and implementation of a DERMS, will support FERC Order 2222, will support the expansion of the distributed generation ("DG") cap from 1% to 10% of utility load under the 2023 Michigan energy law, and will prepare the electric distribution system for the expected growth of DER through standardized DERMS to provide the functionality required to optimize the system. 5 TR 2286. In addition to the EPRI report stating that Consumers Energy's Grid Modernization initiatives should be considered standard, or leading, industry practice, the independent third-party audit recently conducted as part of Case No. U-21305 concluded that DERMs as proposed in the Reliability Roadmap is prudent. 5 TR 2294.

Mr. Coppola's generalized criticisms of DER Optimization should be rejected because they fail to address the numerous benefits that the Company showed DER Optimization will provide.

MEIU witness Albers recommended that the Commission reject the Company's proposed DERMS funding and instead require the Company to finish business planning, benchmarking, and learning before requesting DERMS funding, and to require a workshop to address the several DERMS issues that Mr. Albers identified. 5 TR 3234. Consumers Energy supports MEIU's proposal for a DERMS workgroup. Consumers Energy can initiate the workgroup, which can include topics that MEIU would like to discuss. 5 TR 2297. However, Consumers Energy continues to request approval of the DERMS expenditures requested in this case to fund the onboarding of an industry consultant to assist in organizing the workgroup and developing the business case and implementation. 5 TR 2297. CEO witness Kenworthy described the possibility of using DERs to reduce strain on the grid and recommended that the Company use its upcoming distribution grid plan to analyze use cases. 5 TR 2669. It would be more appropriate to consider Mr. Kenworthy's suggestion as a potential DERMS use case in the DERMS workgroup.

The Company is requesting $6.633 million of funding in the test year for DER Optimization. The Company would plan to use $2.133 million for the workgroup and strategy development and $4.5 million for hardware and software projects. 5 TR 2298. Without this requested funding, the Company will be behind the industry in the area of DER Optimization. *Id*.

2. Streetlighting Capital Expenditures

a. The Commission Should Approve the Company's Streetlighting Capital Expenditures

References in the Record: Schmoekel, 5 TR 2454, 2458-2486, 2490-2504, Exhibit A-12 (DAS-1), Schedule B-5.10

In previous rate cases, Consumers Energy's costs for its streetlighting program were incorporated into the overall spending reported for the Company's electric distribution system. For example, new business requests for streetlighting were incorporated into the overall distribution new business line item and demand failure work for streetlighting was incorporated

into the overall distribution demand failures line item. However, in Case No. U-20963 (the Company's 2021 electric rate case), the Commission directed Consumers Energy to "provide separate reports for its streetlight demand failure data and its low voltage distribution demand failure data." U-20963 Order, page 407. Accordingly, Consumers Energy has separated out all streetlighting related capital costs into their own line items in this case. Exhibit A-12 (DAS-1), Schedule B-5.10.

Company witness Daniel A. Schmoekel is Consumers Energy's Senior Strategy Manager for Electric Distribution. 5 TR 2454. He presented testimony and exhibits describing and explaining the Company's streetlighting programs and supporting the Company's projected test year capital costs related to streetlighting. See Exhibit A-12 (DAS-1), Schedule B-5.10. As shown on Exhibit A-12 (DAS-1), Schedule B-5.10, line 6, columns (i) and (j), respectively, the Company's total capital investments for the streetlighting program are projected to be $24.696 million for the 14-month bridge period ending February 28, 2025 and $30.147 million for the test year ending February 28, 2026. Those totals consist of: (i) $3.970 million (bridge period) and $3.469 million (test year) for streetlighting new business; (ii) $2.479 million (bridge period) and $10.681 million (test year) for planned light-emitting diode ("LED") conversions in the vicinity of an LED demand failure conversion; and (iii) $18.246 million (bridge period) and $15.998 million (test year) for streetlight Demand Failures (which includes LED conversions of failed cobrahead lights but may also include other streetlight Demand Failure costs as well). Exhibit A-12 (DAS-1), Schedule B-5.10, lines (1), (4), and (5), columns (i) and (j).

Mr. Schmoekel's testimony describes the types of streetlighting assets that the Company's owns, which increasingly consists of LED lights, though a significant number of non-LED high intensity discharge ("HID") lights such as high-pressure sodium and metal halide lights remain on

the system. 5 TR 2458-2459. Mr. Schmoekel's testimony explains the Company's overall streetlighting plan and customer engagement strategy, which has the central goal to improve outage restoration performance for its streetlighting customers. See 5 TR 2459-2461. Mr. Schmoekel's testimony also discusses the Company's periodic competitive solicitation process to select new streetlighting technology (5 TR 2480-2486) and provides detail about the Company's reactive LED streetlight conversion plan, including its recent expansion of its reactive conversion plan to include post top streetlights, and progress on the plan (5 TR 2490-2501). Mr. Schmoekel also explains the Company's program for planned conversions of non-failed fixtures in the vicinity of a failed fixture, which provides greater efficiency and cost savings for the Company's long-term plan to convert its entire streetlighting fleet to LED. 5 TR 2501-2504.

Mr. Schmoekel's testimony discusses numerous initiatives of the Company toward improving on streetlight outage restoration performance. 5 TR 2461-2480. Those initiatives include utilizing additional dedicated contractors to perform restoration work (5 TR 2467-2468), enhancements to the Streetlight Outage and Restoration ("SOAR") application to better and more quickly identify lights that are out (5 TR 2472-2480), and completing two pilots to test additional options to improve streetlight outage restoration performance: (i) a patrol and fix program (5 TR 2468-2469); and (ii) use of advanced lighting controls (5 TR 2468-2471). Neither pilot proved to be cost effective to improve outage restoration time, so the Company does not plan to continue the pilots at this time. 5 TR 2469-2470. However, Mr. Schmoekel indicated that the Company will continue to evaluate advanced lighting controls as an option for some municipalities that may find the technology beneficial. 5 TR 2470. The Company is not seeking to recover any of the investments in those two pilots. 5 TR 2469. Those pilots were funded with shareholder dollars.

The capital investments for streetlighting are well-supported and reasonable. The Commission should approve the Company's capital spending proposal for the bridge year and the test year as filed.

b. <u>The Commission Should Reject Staff's Proposed Capital Reduction to Streetlighting Capital and Other Recommendations</u>

References in the Record: Duell, 5 TR 3836-3837; Schmoekel 5 TR 2509-2512

Staff witness Jessica Duell recommended that the Commission reduce the Company's capital spending for its streetlighting program by 20% for the test year in this case. 5 TR 3836. Her reason for proposing this reduction was that the Company did not spend the full amount of the streetlighting capital approved for recovery in rates in the Company's last electric rate case, Case No. U-21389. 5 TR 3836.

Company witness Schmoekel testified that the Company uses five-year historical average expenditures for streetlight failures and street lighting new business capital expenditures to estimate test year projected capital expenses. 5 TR 2509. The projections are then escalated by an inflation rate of 2.4% for 2024, 2.2% for 2025, and 0.4% for 2026. 5 TR 2509. This is a reasonable method to estimate costs for this type of program. In rebuttal, Mr. Schmoekel testified that actual spending on streetlight failures is currently trending at approximately 117% of the Company's original forecast for 2024, which is attributable to the fact that 2024 is the first year of scaled conversions for post top LED conversions that were not included in the historical five-year average. 5 TR 2509-2510. Spending on streetlight new business is trending to be approximately 167% of the Company's original forecast due to increased complexity and scope of some work orders, which increased the unit costs of the installations. 5 TR 2509-2510. It would not make sense to reduce the capital spending for this case when the actual data for current spending shows that it is higher than forecasted rather than lower. 5 TR 2509.

Mr. Schmoekel explained that the Company cannot specifically predict when lights are going to fail. 5 TR 2509. Similarly, new business requests fluctuate year to year based on factors outside of the Company's control. 5 TR 2511. Mr. Schmoekel explained that "[g]iven the variability of the economy, solely using the previous year as a basis for bridge period and test year funding may introduce more volatility in forecasting than a multi-year averaged approach." 5 TR 2511. He testified, "Multi-year averaged approaches have greater probability to capture periods of growth as well as economic downturn, thus resulting in a higher level of confidence in the projected level of spending." 5 TR 2511.

The Company's averaging approach to forecasting such variable costs "ensures that funding is available for the average failure experience over several years." 5 TR 2509. In contrast, Staff's approach to propose a reduction following a below-average year will almost certainly lead to long-term underfunding of the actual program costs, since it is unlikely that Staff or any other party will propose to increase the forecasted amounts in years where the prior year experience was above-average. Applying a consistent and logical methodology is the only fair and reasonable way to project these kinds of costs. Staff's recommended disallowance should be rejected.

Staff witness Duell also took issue with the Company's responses to discovery questions asking the Company to identify where the underfunded streetlight capital amounts from 2023 were spent and recommended that the Company should "give a full description of the distribution expenditures this extra funding is going toward." 5 TR 3836-3837. However, Ms. Duell's recommendation fails to understand how program budgeting works. When funds allocated to Electric Distribution capital programs are not spent, the specific dollars are not traced from one program to another. 5 TR 2512. The Company generally returns budgeted program funds that are unused to an Electric Distribution department level account. 5 TR 2512. That account may

accumulate funds from more than one program with unused funds on a rolling basis as the year progresses. Funds are then reallocated to fund programs with additional capital needs in other parts of the electric distribution organization. 5 TR 2512. Again, this may occur unevenly on a rolling basis as changing circumstances over the course of the year provide new information for management to determine when and where additional funds are needed. Mr. Schmoekel explained that a reason for utilization of this method is that unused funds in one program and capital needs in other programs often occur at different times of the year. 5 TR 2512. At year end, the Company can provide data to Staff about which programs were under budget for the year and which were over budget, but individual dollars are not traced from one program to the next. The level of detail Ms. Duell is requesting does not exist, nor would it be reasonable or practical to manage the business in that way.

Finally, Ms. Duell recommended that Consumers Energy should apply any unused funds in streetlighting to line clearing and storm restoration. 5 TR 3837. However, this would be inappropriate. Mr. Schmoekel explained that "[t]he streetlighting programs Ms. Duell is referencing in her testimony (New Business, Failure, and Conversion) are capital programs and the programs Ms. Duell requests applying excess funds to are O&M programs." 5 TR 3837. Furthermore, Ms. Duell's recommendation is squarely within the ordinary day-to-day management prerogative of the Company, which is reserved by law to the Company's management. See *Union Carbide Corp v MPSC*, 431 Mich 135; 428 NW2d 322 (1988). Staff's recommendation must be rejected.

3. Generation Capital Expenditures

a. Overview

References in the Record: Blumenstock, 5 TR 1388, 1394-1438, Exhibit A-12 (RTB-3), Schedule B-5.2; Monroe, 5 TR 2333, 2395; Clark 5 TR 1596, 1663; Bodiford, 5 TR 1533; Harlow, 5 TR 1655, 1657-1663

Company witness Richard T. Blumenstock, Executive Director of Electric Supply Engineering, testified in support of Consumers Energy's overall generation capital expenditure amounts, and the reasonableness of the expenditures. 5 TR 1388, 1557. His testimony includes an overview of the generating plants owned by Consumers Energy (5 TR 1394-1396), a discussion of the Company's generation asset strategy (5 TR 1396-1399), and the Company's expectations regarding the availability of its generating plants (5 TR 1399-1428). Mr. Blumenstock's testimony also provides detailed support regarding the reasons for specific projects undertaken during the historical year, bridge period, and test year for the Company's fossil fueled generating plants and Ludington Pumped Storage Plant. Company witness Adam J. Monroe provides similar detailed support regarding the reasons for specific projects undertaken during the bridge period and test year for the Company's hydro plants (excluding Ludington Pumped Storage) (see 5 TR 2333, 2395) and Company witness Thomas P. Clark provides detailed support related to the capital expenditures for the Company's solar projects and battery energy storage projects (see 5 TR 1596, 1663).

Mr. Blumenstock testified that maintaining plant safety, reliability, and compliance with regulations are the major drivers of capital expenditures for the generating plants. 5 TR 1432. Although the Company has detailed plans regarding the projects that it intends to complete during the bridge period and test year, Mr. Blumenstock explained that it may need to make changes to scheduled outages and forecasted capital expenditures because the Company often forecasts future actions and expenditures based on currently available information, many months before the work

is completed. 5 TR 1437-1438. This may be due to contractor availability, parts availability, changes in regulations, design changes, outage scope changes, changes in unit condition, and spot market prices. 5 TR 1438. While the forecasted capital projects may change, the Company has a demonstrated history of prudent capital investments in its generating facilities, which the Commission has consistently approved. 5 TR 1438.

The Company's generation asset strategy focuses on onboarding renewable energy resources, including battery energy storage systems ("BESS"), as well as those generating assets that provide the most economic benefit to customers through their energy and capacity value in the respective Midcontinent Independent System Operator, Inc. ("MISO") markets. 5 TR 1396. As Mr. Blumenstock explained, in accordance with the Company's generation asset strategy for each generating unit or category of generating units, economic projects that are expected to reduce random outage rates, maintenance cost, or heat rate, all else being equal, are evaluated to ensure that their implementation results in a net benefit to the customer. 5 TR 1435. For a project to receive approval for implementation, the projected benefits of the work must have a greater value than the cost of implementing the project. *Id*. In other words, the project should result in a marginal customer benefit. *Id*.

Exhibit A-12 (RTB-3), Schedule B-5.2, sets forth the Company's proposed generation capital expenditures for inclusion in rate base for the historic year, projected bridge years, and the test year. Mr. Blumenstock testified in support of Company capital expenditures for its generating plants in the amounts of $859.1 million for 2023, $463.5 million projected for the 14-month bridge period ending February 28, 2025, and $600.5 million for the projected test year ending February 28, 2026. 5 TR 1434; Exhibit A-12 (RTB-3), Schedule B-5.2, page 1. The Company

has not included any contingency amounts in the capital expenditures for which the Company is seeking recovery. 5 TR 1434.

As discussed in more detail below, several parties recommended adjustments to the Company's generation capital expenditures. Due to changing circumstances after the filing of this case, the Company agrees with some (but not all) of the proposed adjustments. In particular, the Company has agreed to adjustments recommended by Staff witness Raushawn D. Bodiford that relate to updated cost projections for certain projects at the Company's fossil fuel plants, Ludington Pumped Storage plant, and other hydro facilities ($5.760 million reduction in the bridge period and $8.894 million increase in the test year). 5 TR 1533. The Company has also agreed to adjustments recommended by Staff witness Jesse J. Harlow to move cost recovery for the capital investments associated with four solar projects (i.e. the Mustang Mile, Washtenaw Solar, Muskegon Solar and Spring Creek Solar projects) from the rate case to the Company's upcoming renewable energy plan case. 5 TR 1655. Finally, although the Company disagrees with proposals by Staff witness Jonathon J. DeCooman and Attorney General witness Deupree to disallow certain of the Company's battery storage project investments, the Company proposes adjustments to the timing of the projects that will have the effect of removing any impact those projects have on the revenue requirement in this case. 5 TR 1657-1663. The cumulative effect of these adjustments is reflected in the capital investments set forth in Exhibit A-257 (HJM-6).

The Commission should approve the Company's generation capital expenditures as proposed by the Company in Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, as adjusted through the Company's rebuttal testimony described above, which adjustments are reflected in Appendix B to this Initial Brief. The Commission should approve the Company's generation capital expenditures as proposed by the Company in Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, as

adjusted through the Company's rebuttal testimony described above, which adjustments are reflected in Exhibit A-257 (HJM-6). Those amounts were fully supported by testimony and exhibits of Company witnesses Blumenstock, Monroe, and Clark. While some of the other parties' witnesses raised issues with respect to particular capital expenditures, their proposed adjustments that were not adopted as part of the Company's rebuttal are without merit, as discussed in more detail below.

b. Fossil Generation and Ludington Pumped Storage

i. The Commission Should Approve the Company's Fossil Generation and Ludington Pumped Storage Capital Expenditures with Staff's Updated Cost Projections

References in the Record: Blumenstock, 5 TR 1445-1485, 1490, 1533, and 1538-1539, Exhibits A-12 (RTB-3), Schedule B-5.2 and A-232 (RTB-13); Bodiford 5 TR 3767-3768, Exhibits S-16.0 and S-16.1; Harlow 5 TR 1655, 1657-1663

Company witness Blumenstock testified regarding the capital projects the Company plans to undertake during the bridge period and test year for its fossil-fueled generating plants and the Ludington Pumped Storage plant. See generally, 5 TR 1445-1483. With respect to the Company's bridge period capital investments, Mr. Blumenstock described any changes to the project plans compared to the test year plans in the Company's last electric rate case. 5 TR 1445-1448. Mr. Blumenstock also provided detailed testimony regarding the bridge period and test year investments required at the following Company generating plants: (i) Campbell Units 1, 2, and 3 (5 TR 1449); (ii) Covert Generation Facility ("Covert") (5 TR 1450-1459); (iii) D.E. Karn ("Karn") Units 1 and 2 (5 TR 1459); (iv) Karn Units 3 and 4 (5 TR 1450-1465); (v) Zeeland Generating Station ("Zeeland") (5 TR 1466-1471); (vi) Jackson Generating Station ("Jackson") (5 TR 1471-1477); and (vii) Ludington Pumped Storage Plant (5 TR 1478-1483). For each plant, Mr. Blumenstock detailed all ongoing and planned projects greater than $1 million as well as a number of projects under $1 million that are important to regulatory compliance and reliability.

Mr. Blumenstock's testimony also supports several generation projects categorized as "Administrative and Other." See 5 TR 1483-1485. The fossil generation and Ludington Pumped Storage projects discussed in Mr. Blumenstock's testimony for the bridge period and test year are also listed in Exhibit A-12 (RTB-3), Schedule B-5.2, pages 8 and 9.

Mr. Blumenstock explained that the proposed capital expenditures on these numerous projects are "directly aligned with the Company's generation asset strategy and, as a result, will provide economic value for power supply customers in the energy and resource adequacy markets." 5 TR 1490. He testified that some of the capital expenditures represented in his extensive list of projects are "related to regulatory and environmental compliance, and thus are not discretionary." *Id*.

Staff witness Bodiford testified that, during discovery, Staff asked the Company for updated estimates of its bridge period and test year capital expenditures for fossil and hydroelectric plants, including Ludington Pumped Storage. 5 TR 3767. The Company provided the requested updates as shown in Staff Exhibit S-16.0. Based on those updates, Staff witness Bodiford recommended that the Commission adjust the bridge period and test year capital expenditures included in rates for this case as shown in Staff Exhibit S-16.1. 5 TR 3768. Mr. Blumenstock agreed that Mr. Bodiford's updated cost estimates reflected in Exhibit S-16.1 are appropriate and should be used to set rates in this case. 5 TR 1533. The effect of these updates results in a reduction in the Company's bridge period capital investments of $5.760 million (for the Company's fossil and hydroelectric plants) and an increase in the Company's test year capital investments of

$8.984 million (for the Company's fossil and hydroelectric plants). See 5 TR 1533 and 5 TR 3768 (which are in agreement).[1]

The majority of the projects detailed in Mr. Blumenstock's testimony for the Company's fossil generation plants and Ludington Pumped Storage, as modified by Staff's proposed updates, have not been contested by any party to this case. Rather than discuss the details of those uncontested projects, this Initial Brief focuses on a discussion of the projects for which one or more parties have recommended an adjustment from the Company's proposed investment in the bridge or test year. Those projects are discussed in more detail in response to each party below. Those projects that Mr. Blumenstock discussed in his testimony or supported through forecasted capital expenditures included in Exhibit A-12 (RTB-3), Schedule B-5.2 which are unopposed should be approved by the Commission as presented in the Company's initial filing in this case and subsequently modified by Staff Exhibit S-16.1.

[1] Although Mr. Bodiford was clear in his testimony that his first adjustment was intended to reflect an increase of $8.984 million for the Company's capital investments in its fossil and hydroelectric plants based on updated estimates obtained through discovery, Staff made an error when translating Mr. Bodiford's recommendation to its revenue requirement calculation. The worksheet that Staff used to translate Mr. Bodiford's recommendation to the final revenue requirement reflects a $2.485 million *reduction* for the updated test year investments. See Exhibit A-232 (RTB-13), page 5, lines 1, 3, and 5. Staff's worksheet inadvertently failed to include any of the adjustments in the "Production (Other)" plant category, which totaled an additional $9.734 million for the test year. See Exhibit A-232 (RTB-13), page 1, line 7. For purposes of eventual cost allocation and rate design, Staff's worksheet also incorrectly allocated some of the dollars attributable to the "Production (Other)" category to the "Production (Steam)" category. Exhibit A-232 (RTB-13) corrects both errors and summarizes the correct method of translating Staff's adjustments to the revenue requirement and rate design. 5 TR 1538-1539. As discussed further below, Consumers Energy opposes Mr. Bodiford's second set of proposed adjustments to the Company's capital investments for its electric generation units, so the Company does not endorse the portions of Exhibit A-232 (RTB-13), page 1, that reflect Staff's second adjustment, specifically lines 2, 4, 6, and 8. However, if the Commission adopts those adjustments, Exhibit A-232 (RTB-13), page 1 reflects their proper allocation.

ii. The Commission Should Reject Staff's Proposed Adjustment Based on the Unsupported and Unrealistic Theory That All Projects Over $1 Million Will Result in Actual Costs at the Low End of the Estimate Accuracy Range

References in the Record: Bodiford, 5 TR 3768-3769, Exhibit S-16.2; Blumenstock, 5 TR 1535-1537

Staff witness Bodiford also recommended that the Commission reduce the Company's generation capital for the test year in this case by $16.720 million on the theory that all of the Company's cost estimates for projects over $1 million will eventually result in actual costs at the lowest end of the expected accuracy range. 5 TR 3768-3770. That recommendation does not reflect a reasonable assessment of the costs the Company will actually incur during the test year. The Commission should therefore reject Mr. Bodiford's adjustment based on the theory that all projects over $1 million in the test year will result in actual costs at the low end of the estimate accuracy range.

Staff witness Bodiford observed that cost estimates for capital projects are less certain at an early stage of project development and become more certain over time. See 5 TR 3769-3770. Consumers Energy utilizes an Enterprise Project Management Organization Cost Estimating Manual ("Cost Estimating Manual") to provide a standard for its cost estimating practices, which is adapted from the Association for the Advancement of Cost Engineering ("AACE") International estimating classes. 5 TR 3768-3769. Depending on the level of development of the project on a scale from five (least developed) to one (most developed), the Company's Cost Estimating Manual identifies an "expected accuracy range" for the cost estimate. See 5 TR 3769, Table 1. For every level of development on the scale except level 5, the accuracy range is expressed as some percent below the estimate to some percent above the estimate, with the range narrowing as the project develops based on an increasing level of the engineering completed. 5 TR 3769, Table 1. Staff

witness Bodiford assumes that all of the Company's projects over $1 million during the test year will result in actual costs below the estimate and consistent with the maximum low end of the expected range. 5 TR 1535; 5 TR 3769-3770.

Company witness Blumenstock explained that Staff's theory for its proposed disallowance in this category is unrealistic. According to Mr. Blumenstock, each of the ranges by class level have an 80% confidence interval. 5 TR 1537. Therefore, there is a very low to zero probability that 100% of the projects have an actual cost at the low end of the accuracy range. *Id*. The probability represented by the range suggests that some estimates will turn out to be low (meaning that the actual project cost was more expensive than the estimate) and some will turn out to be right on or nearly right on. *Id*. In other words, it is statistically unlikely – even improbable – that Mr. Bodiford's downward adjustment will reflect the actual final costs of the projects. And it is likely – even probable – that the final cost of the projects collectively will be at or near the Company's estimated total for those projects. Mr. Blumenstock testified, "The assumption that every single company estimate will turn out to be inaccurately high, such that the actual cost is at the very bottom of the accuracy range for the estimate, is unreasonable." *Id*.

In the Company's last electric rate case, Case No. U-21389, Staff also proposed a reduction of the Company's test year capital investments for its fossil and hydroelectric plants based on the same theory. Despite the Company's objection, the Commission adopted Staff's proposal, emphasizing that Staff's reduction only applied to 11 projects and finding that "[s]ome proportion of the total projects is likely to land at the low end of the range." U-21389 Order, page 54. The Commission should reconsider its conclusion from Case No. U-21389 in this case. First, Company witness Blumenstock testified in this case that, in 2023, the total capital for all generation projects implemented in that year was higher than the projected capital for those same projects. 5 TR 1537.

So, although "some proportion of the total projects" in 2023 may have landed at the low end of the range, some proportion of the projects also necessarily landed at the high end of the range such that the aggregate amount of needed capital investment actually exceeded the Company's original estimate. Mr. Blumenstock explained that, based on historical experience, on average, the actual project costs settle around the projected cost for the projects, including contingency. 5 TR 1537. Second, Staff is now applying the theory to 31 capital investment projects – a nearly 300% increase from the number of projects impacted in Case No. U-21389. Staff's proposal would reduce the Company's recovery of its reasonably estimated costs for 76% of the capital projects over $1 million planned in the test year. The magnitude of Staff's proposed reduction in this case is nearly four times the amount that Staff proposed to reduce under this same theory in Case No. U-21389. Continued ratification of Staff's unsound theory for capital project investments is virtually certain to result in under-recovery of the Company's actual costs for needed generation capital investments during the test year. Mr. Blumenstock explained that, even if the Commission includes the full cost of those investments in later rate cases, after the costs have been historical, this approach guarantees that the Company will fail to recover the depreciation and return that should have been recovered in the first year those investments are in service. 5 TR 1535-1536. The lost increment can never be recovered later despite the fact that the investment was reasonable, prudent, and provided actual service to customers.

Because of this problem, Mr. Blumenstock explained that adopting Staff's theory will likely result in the Company "de-prioritiz[ing] several projects to account for the disallowance to reduce investment to the amount awarded by the Commission." 5 TR 1536. The Company works to align its spending plans with its rate case outcomes. When a rate case fails to supply sufficient funds to perform all of the planned work, the Company will necessarily have to delay or forego

some of that work. Mr. Blumenstock noted that Staff witness Bodiford performed a thorough review of the various information that the Company included in its filing including direct testimony, exhibits, and Part III filing requirements, as well as the responses that the Company provided to Staff through discovery. 5 TR 1534. Yet, Mr. Bodiford offered no substantive criticism of any of the projects the Company identified for necessary capital expenditures during the test year. In other words, Staff apparently agrees that the projects all need to be done, so it makes no sense to intentionally supply insufficient funding in rates to do them. Mr. Blumenstock testified: "Forgoing execution of the projects that are deprioritized will certainly result in degradation of reliability and safety that those projects would have produced had we completed them as planned." 5 TR 1536.

Finally, the Company notes that Staff's proposed reduction based on the theory that all projects over $1 million in the test year will result in actual costs at the low end of the estimate accuracy range is faulty, in part, because it double-counts certain capital investments reductions that have also been recommended for disallowance by Staff witness DeCooman for different reasons. 5 TR 1535, 1537. It is not appropriate to disallow the same dollars of investment twice. Because the particular investments impacted by this defect in Staff's proposal relate to the Company's hydroelectric plant, the Company will discuss this issue again in Section III.A.3.c of this Initial Brief which specifically addresses the Company's hydroelectric investments. However, the Company raises the issue here as further demonstration that Staff's proposed reductions based on class cost estimates is not a sound or appropriate approach and should not be accepted as proposed.

The Commission should reject Staff witness Bodiford's recommended adjustments to the Company's generation capital expenditures in the amount of $16.720 million. The Company's

cost estimates for those projects are reasonable, based on sound cost estimating practices, and reflect the Company's most up to date cost forecast which Mr. Bodiford adopted. The projects are needed and planned for the test year in this case. Again, the reductions proposed by Mr. Bodiford in this category include a mix of projects at the Company's fossil plants and its hydro plants. See Exhibit S-16.2. For further discussion in support of the Company's hydro generation capital expenditures, see Section III.A.3.c. of this Initial Brief below.

iii. Response to ABATE's Proposed Capital Adjustments

ABATE witness York proposed a series of disallowance for 15 individual capital projects planned for the Company's fossil generation fleet in this case. The Company partially agrees with some of Ms. York's proposed reductions, but many are without merit and should be rejected. The Company also emphasizes that emergent circumstances discovered during day-to-day operations may occasionally result in changed investment priorities during the course of a rate case, but that does not support disallowances. Where that occurs, the right approach would be to follow Staff witness Bodiford's example to retain overall investment levels to address the emerging priorities, rather than depriving the utility of that needed funding. The Company addresses each of the projects discussed by ABATE witness York in turn below.

a) The Company Partially Agrees with ABATE's Proposed Disallowances for the Covert Units 2 and 3 SCR Catalyst Replacement

References in the Record: York, 5 TR 3340, Exhibit S-16.1; Blumenstock, 5 TR 1539

ABATE witness York recommended that the Commission disallow all of the Company's bridge period capital investments for Covert Units 2 and 3 (a total disallowance of $2.084 million) on the grounds that "the Company is no longer seeking recovery for them." 5 TR 3340. That claim is only partially correct. Company witness Blumenstock testified that, after filing this case, the Company performed testing that indicates that these two projects can be deferred to 2030.

5 TR 1539. However, a complete disallowance is not appropriate because the Company has incurred a small amount of bridge year investment related to these projects ($142,000 at each unit for a total of $284,000). See Exhibit S-16.1, lines 2 and 3, column (g). Mr. Blumenstock agreed that most of the investment for these projects ($900,000 per unit for a total of $1.8 million) can be removed from the case; however, the Commission should approve recovery of the small remaining investment of $284,000 as recommended by Staff witness Bodiford. 5 TR 1539.

b) The Commission Should Reject ABATE's Proposed Disallowance for the Covert LTSA –Extras

Resources in the Record: York, 5 TR 3342; Blumenstock, 5 TR 1457, 1540-1541, Exhibit A-227 (RTB-8)

ABATE witness York proposes that the Commission disallow $1.748 million in the bridge period and $24.658 million in the test year for the Company's Long-Term-Service-Agreement – Extra Work not Included in the Contract ("LTSA Extras") work at the Covert plant. 5 TR 3342. Ms. York claims that the Company does not explain how the projected capital expenditures were determined and concludes that the work is "speculative." 5 TR 3342. Ms. York also claims that her proposed disallowance is "consistent with the Commission's findings" in Case No. U-21389. 5 TR 3342.

ABATE's claim that its proposed disallowance for the Covert LTSA Extras work in this case is consistent with the Commission's findings in Case No. U-21389 is false and misleading. In Case No. U-21389, the Covert generating plant was a new addition to Consumers Energy's generating fleet, and the Company relied primarily on pre-ownership estimates of the LTSA Extras costs presented in its last IRP as support for the costs that it might incur in the test year of Case No. U-21389 for LTSA Extras work at the Covert plant. The Commission noted the absence of historical data from the previous owner of the plant, which could have been used to develop a more substantive estimate in that rate case. See U-21389 Order, page 56 ("Consumers presented no

historical data in support of the request. The Commission recognizes that the asset has not been under Consumers' ownership for long, but finds it probable that the company had access to data that could have been used to support this funding request.").

Unlike Case No. U-21389, Consumers Energy has now owned the plant for more than a year and has been able to identify specific LTSA Extras work that it will need to perform based on its actual experience operating the Covert plant. For example, Mr. Blumenstock testified about major inspections planned at each of the Covert units during the test year of this case that involve known LTSA Extras work such as "generator inspection, replacement of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing repairs, and HP stop and control valve disassembly, inspection, cleaning, and repair" on Covert Units 2 and 3. 5 TR 1457; see also 5 TR 1540. The support for the Company's estimates for the Covert LTSA Extras work in this case is now similar to the support for the Company's estimates for the Zeeland LTSA Extras work that the Commission approved in Case No. U-21389, despite ABATE's claim in that case that the Zeeland estimates were also "speculative." See U-21389 Order, page 64.

Contrary to ABATE's claims, there is nothing "speculative" about the LTSA Extras work that the Company plans to perform in the test year of this case. Company witness Blumenstock sponsored Exhibit A-227 (RTB-8), which is the Mitsubishi LTSA Plan for Covert Major Outage Inspections for Unit 2. Unit 2 will be the first of the Covert units to begin this work. 5 TR 1540. Mr. Blumenstock further explained:

> The Company has carefully planned these major outage inspections and has coordinated their implementation with Midcontinent Independent System Operator, Inc. ("MISO"). The work to be performed by the Company during the major outage inspections has been clearly defined and [contrary to Ms. York's testimony] the Company did provide the basis for the LTSA extra work in my direct testimony beginning on page 69, line 29, through page 70, line 23. [5 TR 1541.]

ABATE's claims that the Company did not explain how the projected capital expenditures were determined is demonstrably false. The Commission should reject ABATE's proposed disallowance for this category of costs and approve the Covert LTSA Extras work supported by Staff witness Bodiford. 5 TR 1541.

c) The Commission Should Reject ABATE's Proposed Disallowances for (i) the Covert Roll-Up Door Project and (ii) the Covert Loading Dock Project Because the Funds Have Been Reallocated to Other Higher Priority Work that Exceeds the Cost of the Original Proposals

References in the Record: Blumenstock, 5 TR 1452, 1454, and 1542-1545; York, 5 TR 3343-3344

Consumers Energy's fossil generation capital in this case originally included planned projects at Covert for the installation of roll-up doors on all three units (5 TR 1452) and to build out the existing warehouse and add a loading dock (5 TR 1454). ABATE witness York proposed complete disallowance of the costs for both projects ($535,000 for the roll-up door project and $1.817 million for the warehouse and loading dock project). With respect to the roll-up door project, Ms. York argued that the Company had not provided any analysis as to the amount of time that would be saved in moving large equipment in and out of the units or how much cost the Company would be able to reduce. 5 TR 3343. With respect to the warehouse and loading dock project, Ms. York argued that the Company had not provided an assessment of its needs for upcoming major plant outages or future plant maintenance that would be affected by the loading dock or why current arrangements are not sufficient. 5 TR 3344.

In rebuttal testimony, Mr. Blumenstock indicated that these projects were properly supported in the Company's direct testimony (5 TR 1542) and the Company emphasizes that both projects are still needed. However, Mr. Blumenstock explained that, after the filing of the Company's case, Consumers Energy had to re-prioritize its capital spending plans for the fossil

generation plants to address other critical emerging work. 5 TR 1542, 1544. As a result, both of these projects have been moved out of the bridge period and test year timeframes in which they were originally planned. Nevertheless, Mr. Blumenstock explained that the dollars originally associated with these projects should not be disallowed. Instead of the roll-up door and warehouse/loading dock projects, the Company now plans to complete emergent projects, including the Covert load commutated inverter replacements ($520,000), high voltage bushing and oil replacement on the generator step up transformers for Covert Units 1 through 3 ($830,000), and the Jackson high pressure turbine nozzle replacement ($1,484,524), during the bridge period and test year of this case. 5 TR 1542, 1544. The cumulative cost of these emergent projects ($2.835 million) exceeds the cumulative cost of the roll-up door project and the warehouse/loading dock project ($2.352 million). Mr. Blumenstock testified that it would be inappropriate to disallow the costs associated with the originally planned projects when "those dollars (and more) will still be invested for customer benefit on a higher priority project." 5 TR 1542, 1544-1545. The Commission should reject ABATE's proposed disallowance, recognizing that the dollars are still needed to benefit customers on other projects. 5 TR 1542-1543, 1545.

d) <u>The Commission Should Reject ABATE's Proposed Disallowance for the Covert Base Outage Capital</u>

References in the Record: Blumenstock, 5 TR 1453 and 1543; York, 5 TR 3344

Company witness Blumenstock explained that base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages. 5 TR 1453. The Company projected $443,000 in the bridge period and $383,000 for the test year for Covert base outage capital. 5 TR 1453. ABATE witness York recommended that the Commission disallow the entire amount of the Covert base outage capital. 5 TR 3344. Ms. York argued that the Company did not identify specify types of parts that it will

replace as a result of the inspections and claimed that the Company did not explain how it developed its projected amount. 5 TR 3344.

As Ms. York acknowledged, the Company's expenditures under the base outage capital program are necessary for the replacement parts and other issues that will be discovered during major inspections scheduled to occur during the bridge period and test year in this case. Those inspections have not occurred yet. Although it is not possible to identify specifically which parts or issues will be discovered during those inspections, this is a category of capital costs that the Company routinely experiences. The Company must budget for them, and it would be unreasonable to assume that no such costs will be incurred during the bridge period and test year of this case. Furthermore, the Company has a good basis for forecasting the costs. Company witness Blumenstock testified that the Company invested $789,000 in base outage capital during the seven-month period beginning June 1, 2023 and ending December 31, 2023 at Covert. 5 TR 1543. The Company is only projecting $443,000 for Covert base outage capital in this case for the entire 14-month bridge period. In other words, the Company has estimated only half the base outage capital in this case for a 14-month period that the Company actually incurred in a recent seven-month period. The Company's forecast for the 12-month test year is even lower at $383,000. As Mr. Blumenstock testified, the Company's estimates are very conservative compared to the Company's actual experience for these costs. 5 TR 1543. ABATE's proposed disallowance should be rejected.

e) The Commission Should Reject ABATE's Proposed Disallowance for the Covert Steam Turbine Exciter Project

References in the Record: Blumenstock, 5 TR 1457, 1545, Exhibit A-228 (RTB-9); York, 5 TR 3345

Company witness Blumenstock testified that the Company plans to replace the steam turbine exciters for the Covert plant during the test year of the case and estimated that the cost of that project would be $761,667. 5 TR 1457. Mr. Blumenstock explained that the excitation equipment is obsolete and that the gas turbine exciters have already been replaced. 5 TR 1457. Mr. Blumenstock warned that a failure of the steam turbine exciter could lead to both generators on the unit being out of service until replacements can be found. 5 TR 1457. He testified that there is a typical lead time of 18-24 months for replacements. 5 TR 1457. The Company cannot reasonably afford to lose such a significant resource for capacity and energy for up to two years and would incur significant costs for replacement capacity and energy – to the detriment of customers – if such a protracted outage occurred.

Despite these concerns, ABATE witness York recommended that the Commission disallow all of the Company's planned investment to complete this project. 5 TR 3345. Ms. York claimed that the Company did not provide "an assessment of the current status of the existing equipment, information as to whether the replacement exciters have been procured, or the risk of equipment failure during the test year." 5 TR 3345.

Mr. Blumenstock sponsored Exhibit A-228 (RTB-9), which is the Company's draft concept approval document that supports this project. 5 TR 1545. Exhibit A-228 (RTB-9) includes an assessment of the equipment failure risk during the test year. The concept approval document states:

> The risk of failure for the existing AVRs is significant, given their age and obsolete technology. A sound conservative estimate

> suggests a 10% chance of failure, escalating by 20% annually until replaced. The failure of one AVR will result in both the gas turbine generator (GTG) and the steam turbine generator (STG) becoming unavailable, leading to substantial operational and financial impacts. [Exhibit A-228 (RTB-9), page 4.]

Here, it is important to recall that it will take as much as two years to procure the replacement equipment, which means that, even initiating the project during 2025, the Company will experience at least two annual increases in the risk level for failure identified in the concept approval document. It is important to also keep in mind the seriousness of the risk if the unit fails. Furthermore, Mr. Blumenstock testified that the replacement of the steam turbine exciters will save customers at least $8.6 million compared to the other alternatives of doing nothing or running to failure. 5 TR 1545. Therefore, approval of the project is well-justified even if it was expected to have a rate impact in this case. But, it does not have a rate impact in this case. Mr. Blumenstock noted in his rebuttal testimony that the project is not expected to achieve close out until 2027, which is beyond the end of the test year in this case. 5 TR 1545. As a result, the Company's planned test year investments are subject to the offset for Allowance for Funds Used During Construction ("AFUDC"). 5 TR 1545. Granting ABATE's recommended disallowance would serve no purpose in this case other than to further delay this important project.

The Covert steam turbine exciter replacement project is needed and will save customers money, as well as reducing substantial capacity and energy risk. The Commission should reject ABATE's proposed disallowance and approve the test year capital spending proposed by the Company for this project, which will be reflected in rates in a future case.

f) The Commission Should Reject ABATE's Proposed Disallowance for the Karn Sync Wire Replacement

References in the Record: York, 5 TR 3346; Blumenstock, 5 TR 1461-1462, and 1546-1547

ABATE witness York recommended that the Commission disallow $1.26 million of capital investments in the bridge period of this case for the Company's Karn sync wire replacement project. 5 TR 3346. Ms. York argues that the Company's concept approval documents for the project indicate that the project would begin implementation in 2023 and take one year, but that the project bid has not been issued yet and no contractor selected. 5 TR 3346.

Mr. Blumenstock explained that this project had previously been delayed as a result of the Company's last IRP because Consumers Energy was considering retiring Karn Units 3 and 4 early in that case. 5 TR 1546. However, the settlement agreement ultimately approved in the IRP included continued operation of Karn Units 3 and 4. 5 TR 1546. Therefore, the Company must now proceed with the project as originally planned.

The Karn sync wire project involves replacement of the copper communication cables between the Karn plant and Hampton Substation with more reliable fiber optic cables to reduce the risk of possible failure of the units to synchronize correctly or to trip the units offline for a fault event. 5 TR 1461-1462. Failure to synchronize the units properly could result in damage to the generator and turbine, resulting in decreased plant reliability and increased expense. 5 TR 1462. Contrary to ABATE's claims, the Company has moved forward diligently with this project during the pendency of this case. Mr. Blumenstock testified that contracts have now been issued, materials fabricated for the project, and the Company has begun implementation. 5 TR 1547. Specifically, Mr. Blumenstock testified that the work on Karn Unit 3 began on October 7, 2024 and was scheduled for completion on November 7, 2024. 5 TR 1547. Work on Karn Unit 4 was scheduled to begin on November 2, 2024 and finish on November 26, 2024. 5 TR 1547.

The Company had already incurred $673,529.13 in costs for the project as of the date that rebuttal testimony was filed in this case. 5 TR 1547. Therefore, ABATE's proposal to disallow all of the costs associated with this project due to ABATE's baseless doubts about whether the project would in fact be completed is clearly not reasonable. The Commission should reject ABATE's proposed disallowance for the Karn sync wire project and approve the Company's projected capital investments for the project in setting rates.

g) The Commission Should Reject ABATE's Proposed Disallowance for the Karn Unit 4 Expansion Joint Replacement

References in the Record: York, 5 TR 3347; Blumenstock, 5 TR 1465, 1548

ABATE witness York recommended that the Commission should disallow the $1.9 million investment Consumers Energy had originally planned for the replacement of Karn Unit 4 expansion joints during the test year. 5 TR 3347. Ms. York expressed skepticism that there was any confirmed problem with the expansion joints that required repair. 5 TR 3347.

Company witness Blumenstock testified that he does not agree with Ms. York's analysis regarding the deteriorated condition of the Karn Unit 4 expansion joints. 5 TR 1548. Mr. Blumenstock explained that all Karn Unit 4 expansion joints between the ID fans and the stack are beyond their end of life. 5 TR 1465. He further explained that the Company's belief regarding the severely degraded condition of the expansion joints is based on the condition of expansion joints found during the Karn Unit 3 Breeching project. 5 TR 1465. There is no reason to believe that the condition would be different at the two units.

Nevertheless, Mr. Blumenstock testified that other emerging critical work has required the Company to reprioritize this project out of the test year in this case. 5 TR 1548. Although Mr. Blumenstock did not identify the emergent projects that the Company needed to prioritize ahead of this project, Mr. Blumenstock did note that the Company still plans to spend the

$1.9 million originally budgeted for the Karn expansion joints replacement to this other emergent work. 5 TR 1548. Therefore, Mr. Blumenstock urges the Commission not to adopt ABATE's proposed disallowance for these investments. 5 TR 1548.

h) The Company Partially Agrees with ABATE's Proposed Reduction for the Karn Ductwork Insulation and Lagging Replacement Project

References in the Record: Blumenstock, 5 TR 1464-1465 and 1548-1549; York, 5 TR 3348

Company witness Blumenstock testified that Consumers Energy needs to replace the existing lagging and insulation on all the ductwork from the Karn building out to the stack. 5 TR 1464. Mr. Blumenstock explained that the work is required because the steel structure that the ductwork lagging is attached to is severely corroded, which has allowed multiple random failures of the lagging, resulting in a safety concern due to pieces of lagging falling to the ground or becoming airborne during wind events. 5 TR 1464-1465. He testified that the work involves removing the existing lagging and insulation, fixing the underlying steel as necessary, and installing new insulation and lagging. 5 TR 1464.

ABATE witness York claims that the Company has not provided adequate support for this project and recommends complete disallowance of the entire $4.8 million planned investment during the test year. 5 TR 3348. Ms. York argues that the Company had not prepared a concept approval document for the project as of the date her direct testimony was filed. 5 TR 3348. However, that does not necessarily indicate that a project is not moving forward.

In his rebuttal testimony, Mr. Blumenstock explained that, as the Company was moving forward with its preparations for the ductwork and lagging project, the analysis related to that project revealed a wider-scope issue that the Company needs to address with the Karn Unit 4 damper. 5 TR 1548. As a result, the Company prepared a concept approval document to first

replace the Induced Draft fan inlet dampers on Karn Unit 4 in order to eliminate the cause of numerous forced outages at the plant in recent years and save customers in excess of $4.5 million due to capacity losses, among other benefits. See Exhibit A-230 (RTB-11). The cost to replace the dampers is $3.0 million in the test year. 5 TR 1549. Therefore, the Company partially agrees to the reduction proposed by ABATE witness York. 5 TR 1549. The Commission should approve only $3.0 million related to this work in the test year rather than the $4.8 million originally requested – a reduction of $1.8 million in the test year. 5 TR 1549. However, the Commission should reject ABATE's recommendation for a complete disallowance due to the important customer savings and reliability benefits associated with the project.

i) The Commission Should Reject ABATE's Proposed Disallowance for the Zeeland Advanced Gas Path Replacement and Axial Fuel Staging Project

References in the Record: Blumenstock, 5 TR 1469-1470 and 1549-1550, Exhibit A-46 (RTB-7); York 5 TR 3349

Company witness Blumenstock testified that the Company plans to take advantage of a scheduled major inspection outage at its Zeeland plant to complete Phase 1 of a project to integrate Advanced Gas Path ("AGP") and Axial Fuel Staging ("AFS") technologies into the Zeeland plant. 5 TR 1469-1470. The AGP technology will increase the output of the Zeeland plant and improve its heat rate efficiency without compromising reliability. Exhibit A-46 (RTB-7), page 1. The AFS technology will enhance the plant's output turndown capability, which "allows the turbines to operate at lower loads while maintaining emissions compliance, ensuring Zeeland Phase 1 turbines can adeptly support the transition to renewable energy." Exhibit A-46 (RTB-7), page 1. The Company's concept approval document for this project shows that the project is expected to result in nearly $133 million in cost savings from 2025 through 2040 from the upgrade alone, plus an additional $1.75 million from reduced LTSA fees. Exhibit A-46 (RTB-7), page 8.

Despite the substantial cost savings, ABATE witness York recommends that the Commission disallow the entire planned investment in the AGP and AFS project for the bridge period and test year of this case ($20.356 million and $25.744 million respectively). 5 TR 3349. Ms. York argues that the Company did not provide information on the performance and savings associated with other generators that use the AGP technology and did not explain why AFS "is not already a trend in the industry." 5 TR 3349. Those arguments are red herrings. Note that Ms. York does not allege that there is anything inaccurate about the Company's forecasted savings associated with the AGP and AFS project. Instead, she merely diverts attention from the evidence the Company did present to insinuate that some possible evidence may be missing.

In rebuttal, Mr. Blumenstock notes that ABATE never asked the Company for additional information regarding the performance and savings associated with other generation resources in the industry using AGP. 5 TR 1550. However, he further explained that, even if ABATE had requested that information, it is "not necessarily information that is publicly available." 5 TR 1550. Nor, is it evidence that is necessary in order to determine that the AGP and AFS project will produce substantial cost savings for customers. Mr. Blumenstock explained that the project is being administered by the original equipment manufacturer, General Electric, and the basis for the project is, in part, informed by the Company's partnership with them. 5 TR 1550. He also provided 67 pages of data and analysis supporting the Company's savings calculations associated with both the AGP and AFS technologies. Exhibit A-46 (RTB-7).

Although Mr. Blumenstock acknowledges that there is not (currently) significant "penetration" of the AFS technology in the industry, he explained that the total benefit of the project with only the AGP technology is a positive net present value ("NPV") of revenue requirements of $90.8 million based upon a $57 million investment, whereas the total benefit of

the project with both the AGP and AFS technologies is a positive NPV of revenue requirements of $132.8 million based upon a $63.1 million investment. 5 TR 1550. Therefore, the Company can realize an additional savings to customers of $42 million for just an additional $6 million of investment if it implements both technologies.

Finally, Mr. Blumenstock emphasized that the AGP and AFS project is "very important from an operational perspective." 5 TR 1549. He explained:

> First, the upgrade increases the capacity of each unit by 25 MW, or a total capacity increase of 50 MW. This improvement is critical to the Company's ongoing ability to reliably serve its customers and meets its capacity obligations with both the MPSC and MISO. In addition, the upgrade improves the turndown ratio for each of the units, thereby allowing them to operate at lower loads resulting in improved operating profiles which will allow for fewer starts and more operating hours, thereby reducing costs associated with the LTSA. In addition to increased capacity and improved operating profiles, the upgrade will provide for a 2.8% improvement in heat rate efficiency, thereby supporting more economic operation and dispatch, all else being equal. [5 TR 1549.]

Customers will benefit from the additional capacity and efficiency improvements that the AGP and AFS project create. ABATE's proposal would prevent customers from experiencing the power supply cost benefits of the upgrades and would subject customers to a tighter capacity market and more expense associated with the construction or purchase of other capacity needed to fill the gap foregone by this project. 5 TR 1550.

There is no merit to ABATE's arguments for disallowing the AGP and AFS project investments planned for the bridge period and test year of this case. The Commission should reject ABATE's proposed disallowance and include the full cost of the project in calculating rates in this case.

j) The Commission Should Reject ABATE's Proposed Disallowance for the Zeeland LTSA Extras and Adopt the Company's Updated Estimate

References in the Record: York, 5 TR 3349-3350, Exhibit S-16.1; Blumenstock, 5 TR 1551-1552, Exhibit A-231 (RTB-12)

ABATE witness York recommended that the Commission disallow the $3.925 million the Company forecasted for the bridge period and the $4.275 million forecasted for the test year for the Company's LTSA Extras work at the Zeeland Plant. 5 TR 3349-3350. Ms. York claims that the Company does not explain how the projected capital expenditures were determined and concludes that the work is "speculative." 5 TR 3350. That claim is not supported by the record in this case.

Company witness Blumenstock sponsored Exhibit A-231 (RTB-12), which is a copy of the concept approval document that identifies specific costs that the Company will incur in the bridge period and test year of this case for Zeeland LTSA Extras. 5 TR 1551. For example, the Company must provide cranes for lifting the turbine cases and parts for the planned maintenance evolution. Exhibit A-231 (RTB-12), pages 3 and 6. Cranes are an item that are not included in LTSA planned maintenance. In addition, Mr. Blumenstock explained that the LTSA Extras work includes "typical discovery items found on this style of gas turbines" based on the Company's historical outage experience and work that the Company has projected. 5 TR 1551. According to Mr. Blumenstock, some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA. 5 TR 1551. It is also important to note that, if the Company does not perform the LTSA Extras work and continues to run the plant, it would void the equipment warranties.

ABATE proposed a complete disallowance of the Company's Zeeland LTSA Extras during the bridge period (January 1, 2023 to February 29, 2024) of the Company's last electric rate case based on the same argument ABATE made in this case. See U-21389 Order, page 64. The Commission rejected ABATE's proposed $2.9 million disallowance, agreeing with the ALJ in that case that the costs were not "speculative" as ABATE claimed. *Id*. In this case, Mr. Blumenstock testified that the Company's actual Zeeland LTSA Extra investments in calendar year 2023 exceeded $15 million. 5 TR 1552. ABATE's claims and proposed disallowance proved to be incorrect in Case No. U-21389, and ABATE has not provided any different evidence in this case. It would be unreasonable to disallow any rate recovery, as ABATE has proposed, where there is a known historical outage experience that allows the Company to reliably estimate the need for this type of work and the expected cost.

Although the Commission should reject ABATE's proposed disallowance, Mr. Blumenstock testified that the Company has updated its cost estimates for the Zeeland LTSA Extras work in this case. 5 TR 1551. The Company has reduced its projected bridge period investment from $3.925 million to $1.233 million, and increased its projected test year investment from $4.275 million to $4.355 million. 5 TR 1551. Staff witness Bodiford reviewed these updated cost estimates as part of his audit of the Company's case and incorporated these updated costs into his generation capital recommendation. See Exhibit S-16.1, page 1, line 11, and page 2, line 13. The Commission should reject ABATE's proposed disallowance for the Zeeland Plant LTSA Extras and instead adopt the bridge period and test year investments recommended by Staff.

k) The Commission Should Reject ABATE's Proposed Disallowance for the Zeeland Base Outage Capital

References in the Record: York, 5 TR 3350-3351; Blumenstock, 5 TR 1553

Just as she did with the Covert base outage capital, ABATE witness York recommended that the Commission disallow the entire amount of the Zeeland base outage capital that the Company forecasted for the bridge period ($483,000) and test year ($424,000) in this case. 5 TR 3350-3351. Once again, Ms. York argued that the Company did not identify specify types of parts that it will replace during as a result of the inspections and claimed that the Company did not explain how it developed its projected amount. 5 TR 3350-3351.

The Commission should reject ABATE's proposed disallowance for the Zeeland base outage capital for the same reasons discussed above in response to ABATE's proposed disallowance of the Covert base outage capital. Again, the Company's expenditures under the base outage capital program are necessary for the replacement parts and other issues that will be discovered during major inspections scheduled to occur during the bridge period and test year in this case. Those inspections have not occurred yet. Although it is not possible to identify specifically which parts or issues will be discovered during those inspections, this is a category of capital costs that the Company routinely experiences. The Company must budget for them, and it would be unreasonable to assume that no such costs will be incurred during the bridge period and test year of this case. Furthermore, the Company has a good basis for forecasting the costs. Company witness Blumenstock testified that the Company's average investment required for Zeeland base outage capital over the past six years has been $814,000 annually. 5 TR 1553. As with the Covert base outage capital, the Company's forecasted cost of $483,000 for Zeeland base outage capital during the 14-month bridge period and $424,000 for the test year are very conservative. ABATE's proposed disallowance should be rejected.

l) The Commission Should Reject ABATE's Proposed Disallowance for the Jackson LTSA Extras

References in the Record: York, 5 TR 3351-3352; Blumenstock, 5 TR 1554-1555

ABATE witness York recommended that the Commission disallow the $2.908 million the Company forecasted for the bridge period and the $350,000 forecasted for the test year for the Company's LTSA Extras work at the Jackson Plant. 5 TR 3351-3352. Consistent with her arguments regarding the Covert and Zeeland LTSA Extras, Ms. York claims that the Company does not explain how the projected capital expenditures were determined and concludes that the work is "speculative." 5 TR 3352. Once again, that claim is not supported by the record in this case.

Company witness Blumenstock identified numerous specific projects that the Company has planned to perform in the bridge period and test year under the Jackson LTSA Extras category of investments. During the bridge period, Mr. Blumenstock testified that the investment is required to complete a Nozzle Assembly Replacement on the Jackson plant, an overhaul of high- and low-pressure turbines related to an unserviceable engine, and to address borescopic inspection findings. 5 TR 1554. During the test year, the planned LTSA Extras investment is needed to perform remediation of unserviceable engine conditions and to address additional borescopic inspection findings. 5 TR 1554. Mr. Blumenstock showed that Consumers Energy's average cost for its Jackson LTSA Extras over the past six years has been approximately $2.5 million annually. 5 TR 1554. The Company's forecasted Jackson LTSA Extras investments in this case are in line with that average and, in the case of the Company's test year forecast, actually very conservative. Once again, the projected amounts are supported by specific project work and the investment amounts are well within the historical spend for this type of work. 5 TR 1555. The Commission

should reject ABATE's proposed disallowance and approve the amounts projected by the Company for inclusion in calculating rates.

m) The Commission Should Reject ABATE's Proposed Disallowance for the Jackson Base Outage Capital

References in the Record: York, 5 TR 3352; Blumenstock, 5 TR 1556

Just as she did with the Covert and Zeeland base outage capital, ABATE witness York recommended that the Commission disallow the entire amount of the Jackson base outage capital that the Company forecasted for the bridge period ($350,000) and test year ($300,000) in this case. 5 TR 3352. Once again, Ms. York argued that the Company did not identify specify types of parts that it will replace during as a result of the inspections and claimed that the Company did not explain how it developed its projected amount. 5 TR 3352.

The Commission should reject ABATE's proposed disallowance for the Jackson base outage capital for the same reasons discussed above in response to ABATE's proposed disallowance of the Covert and Zeeland base outage capital. Again, the Company's expenditures under the base outage capital program are necessary for the replacement parts and other issues that will be discovered during major inspections scheduled to occur during the bridge period and test year in this case. Those inspections have not occurred yet. Although it is not possible to identify specifically which parts or issues will be discovered during those inspections, this is a category of capital costs that the Company routinely experiences. The Company must budget for them, and it would be unreasonable to assume that no such costs will be incurred during the bridge period and test year of this case. Furthermore, the Company has a good basis for forecasting the costs. Company witness Blumenstock testified that the Company's average investment required for Jackson base outage capital over the past six years has been $610,000 annually. 5 TR 1556. As with the Covert and Zeeland base outage capital, the Company's forecasted cost of $350,000 for

Jackson base outage capital during the 14-month bridge period and $300,000 for the test year are very conservative. ABATE's proposed disallowance should be rejected.

c. The Commission Should Approve the Company's River Hydroelectric Generation Capital Expenditures

References in the Record: Monroe, 5 TR 2333-2395, Exhibits A-143 (AJM-1), A-144 (AJM-2) and Confidential Exhibit A-149 (AJM-7); Blumenstock, 5 TR 1418-1423, Exhibit A-12 (RTB-3), Schedule B-5.2; Bodiford, Exhibit S-16.1

Company witness Monroe, Executive Director of Hydro Generation, testified to the Company's historical and proposed capital expenditures for the river hydroelectric generating facilities ("River Hydros"). 5 TR 2333-2395. Consumers Energy currently owns and operates 13 FERC-licensed River Hydros. 5 TR 2336. The River Hydros were purposefully built for electric generation in rural locations with communities developed around them. 5 TR 2336. Exhibit A-143 (AJM-1) provides a high-level overview of the Company's River Hydros and provides background information about each facility; Exhibit A-144 (AJM-2) discusses the benefits these facilities provide to local communities and the state. These facilities have a collective maximum theoretical generating capability of approximately 133 MW. 5 TR 2337. However, the facilities have a cumulative Generation Verification Test Capacity of 76 MW because generation output is at least somewhat limited by natural river flows. See 5 TR 2337.

Since their construction, local communities surrounding the Company's dams and their impoundments (*i.e.*, the artificial lakes or ponds created by dams on their upstream side) have grown and come to rely on recreational, environmental, economic, and other benefits created by the facilities. 5 TR 2336. The Company works closely with local governments and residents, as well as state, federal, and tribal resource agencies, to manage these resources for the benefit of surrounding communities, Michigan residents, and out-of-state visitors who contribute to local economic benefit. 5 TR 2336. An example of this is the Hardy Dam impoundment which is a

3,902-acre lake that is highly integrated with the surrounding community, providing enhanced sources of recreation, tourism, and associated business opportunities in addition to approximately 30 MW of reliable, round-the-clock clean energy. 5 TR 2336-2337.

Each River Hydro is subject to FERC regulation and has a project license issued by FERC and a corresponding, unique project number. 5 TR 2339. The FERC project numbers and license dates are provided in Exhibit A-143 (AJM-1). Eleven of the Company's 13 FERC project licenses for River Hydros are set to expire (if not renewed) in 2034. Exhibit A-143 (AJM-1), page 2. The project licenses for two facilities will expire (if not renewed) at a later date – 2040, for the Calkins Bridge (Allegan) Dam, and 2041, for the Webber Dam. Exhibit A-143 (AJM-1), page 2. The FERC project license renewal process typically takes about six years and is being evaluated as one option as a part of the River Hydro long-term strategy evaluation. 5 TR 2339.

FERC comprehensively regulates the Company's River Hydros under Part I of the Federal Power Act and corresponding regulations. 5 TR 2340. FERC's jurisdiction and authority includes dam safety, environmental protection, and operations. 5 TR 2340. Each facility is governed by the terms of its specific FERC project license and corresponding documents (*e.g.*, Land Management Plans), which impose a variety of restrictions and obligations on the Company under federal law. 5 TR 2340. The Company works closely and collaboratively with FERC staff to ensure compliance with these obligations at all times. 5 TR 2340. The capital investments and O&M expenses presented by the Company are necessary for compliance with FERC obligations,

including FERC Part 12D regulations and the FERC-required Company-wide Owners Dam Safety Program.[2] 5 TR 2340.

The Company's strategic plan for the River Hydros is currently predicated on operating the units for the foreseeable future consistent with the Company's FERC project licenses and continued operation is assumed in the Company's approved 2021 IRP in Case No. U-21090. 5 TR 2343. These units create customer value by providing stable, round-the-clock renewable energy and capacity within the Company's generating portfolio. 5 TR 2343. River Hydros also provide value to their surrounding local communities and to the state of Michigan in the form of recreational opportunities, natural preservation, and environmental benefits. 5 TR 2343. The overall long-term objective for the River Hydro units is to maintain safe and reliable River Hydro sites for customers, to ensure compliance with FERC obligations and other regulatory requirements, and to continue providing valuable benefits to local residents, surrounding communities, and the state of Michigan. 5 TR 2343.

As a result of a settlement agreement in the Company's most recent depreciation case, Case No. U-20849, Consumers Energy agreed to present a retirement and decommissioning analysis to the Commission on its River Hydro units by the end of 2024 in the Company's next electric depreciation case. 5 TR 2343.[3] As part of the analysis, the Company will evaluate each facility and determine the best path forward from the perspective of Consumers Energy, its customers, and the state of Michigan. 5 TR 2343. Consumers Energy is considering four options for each of its River Hydros: (i) relicensing the River Hydro dam and continuing to generate electricity;

[2] The FERC Part 12D process refers to Part 12D of the Code of Federal Regulations, Title 18, Chapter 1, Subchapter B. 5 TR 2342. Part 12D, among other things, requires an independent consultant inspection for Consumers Energy's dams every five years. 5 TR 2342. This is a proactive dam safety process in which Consumers Energy reviews its facilities for dam safety issues, works with third-party consultants who make recommendations, and then proposes projects along with timing and priority to FERC. 5 TR 2342.

[3] The Commission recently granted Consumers Energy an extension on filing the next electric depreciation case until the end of 2025. See MPSC Case No. U-21783, November 7, 2024 Order.

(ii) selling the dam to a third party; (iii) removing the dam; and (iv) replacing the dam with an alternative structure that maintains some level of reservoir. 5 TR 2344. In Case No. U-21224, the Company's 2022 electric rate case, the parties also reached a settlement in which the parties agreed that Consumers Energy would (i) obtain economic business cases performed by an outside engineering firm with experience in dam engineering, construction, and decommissioning and (ii) perform an economic assessment of various retirement scenarios before commencing construction of the needed Hardy Dam upgrades. 5 TR 1418-1419. In the Company's last electric rate case, the Commission also directed Consumers Energy to file a "full evaluation of all alternative options and pricing for the work that must be done in order to remain in compliance with [FERC] standards, with projected total costs" if the Company seeks cost recovery for Hardy Dam upgrades in this case.

To address these requirements, Consumers Energy hired Public Sector Consultants ("PSC") to perform an economic study and assist with community outreach. 5 TR 2344. In 2023, Consumers Energy along with PSC held a second round of River Hydro in-person listening sessions and two virtual meetings to provide an update on the River Hydro long-term strategy and receive public input on the long-term future of the River Hydro dams. 5 TR 2344. PSC has produced individual studies for each dam to better understand the unique economic contributions of all 13 River Hydro sites – including additional data on how the hydro facilities and their associated reservoirs contribute to the recreational and tax bases of the communities. 5 TR 2345. In addition, Consumers Energy contracted with WSP USA ("WSP"), a national consulting company with expertise in hydroelectric generating facilities, to provide a "roadmap" for each River Hydro, as well as an economic analysis for each site. 5 TR 2345. Each roadmap identifies objectives to meet the long-term goals for the portfolio of projects based on a desktop review of

existing documents such as licenses, operations, resource studies, revenue projections, plans and budgets, as well as interviewing Consumers Energy staff, and identifying information data gaps. 5 TR 2345. The WSP economic analysis includes a pro forma quantitative financial model for the value of each site for the various road map scenarios and includes an evaluation of the potential value of hydropower to electrical grid operations, considering impact on baseload, impact of increased generation (as a result of relicensing with unit upgrades), and the commercial value of each site. 5 TR 2345. The studies for each of the 13 River Hydros being performed by WSP and PSC will inform Consumers Energy's evaluation of whether to relicense/decommission/divest each of the 13 hydroelectric plants. 5 TR 2345. Company witness Monroe sponsored the WSP roadmap as Confidential Exhibit A-149 (AJM-7). PSC's economic analysis can be found on the Consumers Energy Hydro Futures website. 5 TR 2345. These materials collectively satisfy the requirements discussed above from Case Nos. U-20849, U-21224, and U-21389.

On February 15, 2024, Consumers Energy launched a Request for Proposal ("RFP") to identify potential buyers for the Company's 13 River Hydros. 5 TR 1420. The RFP involves a two-stage process. 5 TR 1420. The first stage involves receipt of bids and bidder screening for the qualifications of the buyer and indicative pricing. 5 TR 1421. Consumers Energy received responses on March 15, 2024 and completed bid evaluation in April 2024. 5 TR 1421. The Company has now moved into the second stage of the process, which involves engaging with seven selected potential buyers for due diligence review and negotiations toward a potential sale agreement. 5 TR 1421. The Company plans to make a decision on the potential sale of the River Hydros by the end of 2024. 5 TR 1422.

Company witnesses Blumenstock and Monroe testified that, regardless of the future of the River Hydros, Consumers Energy must maintain safe operation of its River Hydros as long as they

are licensed under FERC authority by the Company. 5 TR 1423, 2346. Company witness Monroe provided detail about the most significant projects planned for the bridge period and test year at each of the River Hydro facilities, including the capital investment needed to perform each project. See 5 TR 2348-2381. Mr. Monroe explained that all of the planned investments described in his testimony are required to ensure continued safe and reliable operation of the facilities. 5 TR 2344. Mr. Monroe stated that, if the Company cannot make safety and reliability upgrades to the River Hydros, including those that are required by FERC, retirement and decommissioning will likely become necessary to ensure public safety and compliance with FERC regulations. 5 TR 2344. The Company's planned investments during the bridge and test year are necessary to ensure the continued and safe operation of the facilities. As the Company will discuss further later in this Initial Brief, they are also necessary to preserve the Company's options until Consumers Energy can make a thoroughly considered final decision about the best way to address the future of these plants, which the Company expects to be able to make early in 2025. 5 TR 1422-1423.

The Company originally requested recovery of investments totaling approximately $42.376 million in the 14-month bridge period and $92.258 million in the projected test year for the River Hydros, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 7, columns (e) and (f), respectively. As discussed above, Staff witness Bodiford proposed some adjustments in the Company's original capital investment plans based on updated estimates provided in discovery. See Section III.A.3.b.i. of this Initial Brief. Mr. Bodiford's adjustments included updated investment projections for some of the River Hydro projects. See Exhibit S-16.1, page 1, lines 20-29, and page 2, lines 20-33. The Company agrees with those adjustments. The projected capital investments will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. 5 TR 2374. The Commission should adopt the Company's River Hydro investments as

adjusted by Staff Exhibit S-16.1 in setting rates in this case. Alternatively, the Commission could authorize the Company to record the revenue requirement of actual spending for the River Hydros for the bridge period and test year to a regulatory asset until the determination of the future of the River Hydros is certain and base rates are set to appropriately include actual spending. 5 TR 2390-2391.

Because the Company's planned investments at the Hardy Dam comprise more than 60% of test year investments for the River Hydros in this case, the Company discusses the major projects at the Hardy Dam in more detail below.

i. Consumers Energy's Planned Projects for the Hardy Dam are Necessary for Safety and to Comply with FERC Licensing Requirements

References in the Record: Monroe, 5 TR 2348-2349

The Company expects to make several significant dam safety-related investments, totaling over $350,000,000, at the Hardy hydroelectric facility ("Hardy"), FERC Project No. P-2452, through 2027. 5 TR 2348. The Company's proposed investments in Hardy, like most of the Company's investments in River Hydros, are necessary to meet FERC's dam safety requirements. 5 TR 2349. Specifically, working with FERC and independent consultants engaged by the Company to comply with FERC Part 12D regulations, the Company has identified a critical need to replace the auxiliary spillway, replace the splash wall, and compact loose zones of the embankment crest at the Hardy facility. 5 TR 2349.

a) Hardy Spillway Replacement

References in the Record: Monroe, 5 TR 2350-2359, Exhibit A-145 (AJM-3); Bodford, Exhibit S-16.1

In connection with the Hardy auxiliary spillway replacement, the Company intends to spend $3.564 million in the 14-month bridge period beginning January 1, 2024, and ending

February 28, 2025, and $54.953 million in the projected test year ending February 28, 2026.[4] An auxiliary spillway is one type of pathway for discharging water from the impoundment upstream of a dam to the river downstream of a dam. 5 TR 2350. At Hardy, there are three such pathways: (i) water can be released from the impoundment into the plant penstocks (*i.e.*, the large, enclosed pipes that intake water and pass it to and through the generator turbines) and used to generate electricity; (ii) water can be released from the impoundment into the plant spill tubes and passed beneath the dam; and (iii) water can be released into the auxiliary spillway. 5 TR 2350. This spending at Hardy is necessary because the existing Hardy auxiliary spillway no longer meets FERC's requirement that the facility pass the Probable Maximum Flood ("PMF"), and therefore requires replacement.[5] 5 TR 2350. In combination with the concrete deterioration, and the existing soil and groundwater conditions at the site, its use during a PMF event could lead to a dam breach and potential failure, which could cause a cascading failure of the downstream Croton Dam, as well as other downstream infrastructure along the river. 5 TR 2358-2359.

The Hardy auxiliary spillway needs to be replaced because the FERC-required Part 12D inspection of the dam in 2014 resulted in a recommendation from the FERC-required independent consultant for remediation of the auxiliary spillway. 5 TR 2351-2352. However, the associated design and planning was postponed due to the Oroville Dam spillway incident in 2017, with FERC concurrence, to ensure lessons learned from that event could be incorporated into the Hardy design. 5 TR 2352. Following the Oroville incident, FERC required owners and operators of FERC-licensed dams with spillways like the one at Oroville – Hardy included – to perform detailed spillway inspections and analyses. 5 TR 2352; see also Exhibit A-145 (AJM-3). Due to FERC's

[4] These amounts represent the adjusted cost estimates for the bridge period and test year for this project shown in Staff's Exhibit S-16.1, page 1, line 24, and page 2, line 27.

[5] A PMF is the flood that may be expected from the most severe combination of critical meteorologic and hydrologic conditions that are reasonably possible in the drainage basin under study. 5 TR 2355.

heavy focus on spillway capacity issues – including its requirement that Consumers Energy use an independent Board of Consultants ("BOC") for this project, its oversight of interim risk reduction measures, and its new Part 12D regulations – FERC would not permit continued operation of the Hardy Dam without the proposed auxiliary spillway project. 5 TR 2354.

Following an independent consultant's recommendation in 2014 to address the Hardy auxiliary spillway issue and further discussion with FERC, an options study was performed in May 2019. 5 TR 2354. In addition, the Company engaged an engineering consultant to update the PMF as a best practice in 2019 to validate the flood design criteria and FERC approved the updated PMF. 5 TR 2354. The options study considered seven alternative replacement options, as well as doing nothing and selling the asset. 5 TR 2356. The options included various alignments, inlet structures, energy dissipaters, conveyance structures, and Inflow Design Flood requirements. 5 TR 2356. Locating the auxiliary spillway on the left side of the dam (*i.e.* the opposite side of where it is currently located) was not chosen due to several identified disadvantages compared to building the auxiliary spillway in the proposed location on the right. 5 TR 2356-2357.

The options study determined that a labyrinth overflow weir or gated spillway structure was preferable for passing the PMF. 5 TR 2357. This chosen approach follows industry standards to safely pass the PMF, meets FERC design standards, and will pass the PMF at the facility preventing overtopping failures. 5 TR 2357. Design of the selected alternative began in January 2020 with a capital expenditure for preliminary engineering of $3.1 million in 2020, and final engineering of $5.2 million in 2021, $3.1 million in 2022, $2.6 million in 2023, and $2.9 million in the bridge period. 5 TR 2357. This includes the cost of design work, the cost of the

FERC-required independent BOC costs[6], and the cost of FERC required studies. 5 TR 2357. Construction will start in the test year. 5 TR 2357.

b) Hardy Splash Wall Replacement

References in the Record: Monroe, 5 TR 2349, 2362-2363

In connection with the Hardy splash wall replacement, the Company intends to spend $163,333 in the 14-month bridge period beginning January 1, 2024, and ending February 28, 2025, and $2.760 million in the projected test year ending February 28, 2026. 5 TR 2349. The Hardy splash wall is part of the hydraulic barrier separating the upstream impoundment from the downstream river – essentially, part of the barrier that allows the dam to retain and impound water. 5 TR 2362. This section of the barrier is exposed to weather and wave action with the seasonal lowering of the impoundment and therefore it has deteriorated. 5 TR 2362. The scope of this project is to replace the deteriorated splash wall and sloping slab to ensure overtopping protection, wave run-up protection, and a connection to the new auxiliary spillway (closing the "window section"). 5 TR 2362. The improvement to the hydraulic barrier includes ensuring a hydraulic seal between the concrete core wall and the new section of sloping slab, closing the window section, improvements for seismic deformation findings, and necessary updates for the updated PMF. 5 TR 2362. This project will also result in dam road and walkway improvements that will be funded by Consumers Energy and Newaygo County. 5 TR 2362-2363.

FERC is involved in the splash wall project. The Company routinely monitors its facilities for such deterioration and appropriately plans for and implements repairs, often working with FERC and FERC-required independent consultants, and FERC has previously approved Hardy splash wall repairs in 2018. 5 TR 2363. During the 2019 Hardy site risk review, the hydraulic

[6] Utilization of a BOC was required by FERC in a letter to Consumers Energy dated November 1, 2019. See Exhibit A-145 (AJM-3).

barrier was identified as a component that can increase or reduce risk to a dam failure at the site. 5 TR 2363. One recommendation of the risk review was to implement improvements to the entire upper hydraulic barrier as a Risk Reduction Measure. 5 TR 2363.

c) Hardy Crest Compaction and Roadway Replacement

References in the Record: Monroe, 5 TR 2349, 2364-2365

For crest compaction and roadway replacement, the Company intends to spend $236,210 in the 14-month bridge period beginning January 1, 2024 and ending February 28, 2025, and $680,825 in the projected test year ending February 28, 2026. 5 TR 2349. The crest compaction and roadway replacement project is related to the auxiliary spillway and splash wall project. 5 TR 2364. This project was identified and initiated through the FERC Part 12 process and is being executed to eliminate a dam safety and public safety risk to the roadway along the dike crest. 5 TR 2364. Company witness Monroe explained that there are voids occurring along the dike crest and roadway that develop into potholes and washouts, impacting safe travel and dam safety monitoring, and these must be repaired through compaction of the crest and replacement of the roadway. 5 TR 2364. The voids are due to construction methods at the time Hardy was built and the Company has remediated this issue from time to time. 5 TR 2364-2365. With removal of the Hardy roadway for purposes of the auxiliary spillway and splash wall projects, the Company determined that a more extensive repair project should be undertaken to prevent more costly repairs in the future. 5 TR 2365. Engineering and design for the planning crest compaction and roadway replacement project began in 2020 and the Company expects to receive final approval for construction from FERC by June 2025. 5 TR 2365.

ii. The Commission Should Reject the River Hydro Project Disallowances Proposed by Staff, the Attorney General, and ABATE

References in the Record: DeCooman, 5 TR 3669-3671; Deupree, 5 TR 2920-2922; York, 5 TR 3354-3355; Monroe, 5 TR 2384-2391; Blumenstock, 5 TR 1526-1527, 1537; Bodiford, Exhibit S-16.1

Staff witness DeCooman recommended that the Commission reduce the Company's planned capital expenditures for the three Hardy projects discussed above in the bridge period by $1.190 million (for the Hardy Spillway project), $208,100 (for the Hardy Crest Compaction project), and $131,000 (for the Hardy Splash Wall project). 5 TR 3670. Mr. DeCooman recommended disallowance of all of the Company's proposed capital investments during the test year for those Hardy projects (totaling $57.295 million). 5 TR 3670. Mr. DeCooman based his recommended disallowances on a discovery response in which the Company indicated that, if it proceeds to decommission the River Hydros, the Company would prioritize decommissioning the River Hydros with the largest near-term investments in order to avoid those costs. 5 TR 3669-3670. Mr. DeCooman reasoned that the costs should not be allowed in rates if there is a chance that the costs may be avoided. 5 TR 3671.

Attorney General witness Deupree recommended that the Commission disallow all capital investments for all 13 of the Company's River Hydros during the bridge period and test year (a total of $134.6 million). 5 TR 2921-2922. Similar to Staff, Mr. Deupree argued that there is "some uncertainty regarding the need for these investments" because of the Company is currently in the process of evaluating the future disposition of the plants. 5 TR 2921-2922. Mr. Deupree also claimed that the decision to invest in the River Hydros at this time is a function of the Company's judgment, rather than any FERC directives. 5 TR 2920.

ABATE witness York also recommended that the Commission disallow all capital investments for all 13 of the Company's River Hydros during the bridge period and test year (a

total of $134.6 million). 5 TR 3355. Like Staff and the Attorney General, Ms. York argues that "the future of these facilities are unknown at this time, and it may not be reasonable or prudent to proceed with significant capital investment in these facilities at this time." 5 TR 3353. Ms. York also speculates that FERC might allow certain Interim Risk Reduction Measures ("IRRMs") that could delay the need for the Company's planned River Hydro investments or that the Company might be eligible to receive incentives from the U.S. Department of Energy to partially defray some of the costs. 5 TR 3354-3355. As an alternative to complete disallowance, Ms. York argues that the Commission should at least disallow the investments related to the Hardy projects in this case. 5 TR 3355.

The Commission should reject all three parties' recommendations. Company witness Monroe testified that, although there may be some uncertainty with respect to the future ownership or continued operation of the River Hydro facilities, "there is no uncertainty as to the need for reasonable and prudent investments to meet FERC's dam safety requirements or other regulatory requirements . . . ." 5 TR 2386 (emphasis added). Contrary to Attorney General witness Deupree's claim, the safety-related investments required at the Company's River Hydro plants are not merely a matter of Consumers Energy's "judgement." Mr. Monroe explained: "When FERC grants a utility a license to operate a hydroelectric facility, FERC expects compliance with all operational and safety requirements of federal law and regulations. FERC does not expect that utilities will wait to comply with federal regulatory requirements until they are specifically told to do so." 5 TR 2384. Thus, the Company works closely and proactively with FERC to coordinate on projects that FERC requires in order to satisfy the conditions of the Company's licenses, including "negotiation of project schedules which are approved by FERC and, ultimately, become the regulatory requirement at the facility and the Company." 5 TR 2384. As a responsible owner, the Company

does not and cannot wait until FERC orders the Company to take compliance actions or threatens license compliance/revocation prior to starting hydro safety improvement projects. 5 TR 2384-2385. Waiting for FERC to order the Company to comply with its license requirements would delay safety investments and ultimately increase the risk of dam failure to the communities and people that live downstream of the Company's River Hydro facilities. 5 TR 2385. The Company's planned investments in its River Hydro plants is not a discretionary choice that can be casually deferred. The Company's proposed investments in the River Hydro facilities are *necessary* to meet FERC's dam safety requirements or other regulatory requirements. 5 TR 2387.

Furthermore, the potential sale of the River Hydro plants does not mean that the investments planned in this case would be avoided. Company witness Blumenstock testified that closing of any potential divestiture will be "dependent upon state and federal regulatory approval, which would likely be in early 2026 at the earliest and, as such, the Company's investments through the test period would not be avoided and would still be made." 5 TR 1526. The Company cannot put all investment on hold for the next 15 to 18 months as it awaits approval for divestment, as that would risk its compliance with FERC's license requirements. 5 TR 1526-1527.

Disallowing the Company's planned River Hydro investments in this case would undermine all of the Company's ongoing work to identify the disposition of these assets that is best for the Company, customers, and the impacted communities. Right now, the Company has three options available for the future of the River Hydro plants: (i) sale of the River Hydro facilities; (ii) relicensure and continued operation; or (iii) decommissioning. The Company has invested, and continues to invest, considerable time and effort to evaluate and explore the feasibility of those three options so that the final decision about the future of the plants will be the right one for all the impacted stakeholders. But, Consumers Energy cannot reasonably – and will

not – make the investments proposed in this case if it does not have some assurance of cost recovery. 5 TR 2388-2389. Mr. Monroe explained that without these investments, the Company would be unable to implement activities to maintain FERC license compliance, dam safety, and the impoundments for the communities, creating "a significant risk that FERC could eventually revoke the licenses of one or more of the River Hydro facilities or at least telegraph that it will not renew the licenses." 5 TR 2389. The option to relicense would effectively be gone. Furthermore, Mr. Monroe explained that "[a]ny potential buyers would likely be unwilling to complete the sale under those conditions." 5 TR 2389. Company witness Blumenstock explained that this is because prospective buyers "would be uncertain as to the condition of the assets they may be purchasing considering they would have no investment or maintenance for an extended period" and because, if the Company's license was revoked (or at least certain not to be renewed), "the Company would be left with essentially nothing to sell . . . ." 5 TR 1526. Mr. Monroe testified: "This chain of events could effectively force the Company to proceed with decommissioning the River Hydro facilities by severely jeopardizing the Company's ability to relicense or sell the facilities." 5 TR 2389.

It would be premature and unwise to effectively force the Company into decommissioning these plants before the analysis of alternative options is complete. Decommissioning itself is not without significant costs. Decommissioning would result in a loss of generation and capacity to serve Consumers Energy's customers. 5 TR 2389. Decommissioning will also have significant impacts on the communities surrounding the River Hydro facilities. 5 TR 2389. Decommissioning itself will require "extensive decommissioning expense." 5 TR 2390. And, even if the Company does move toward decommissioning, Mr. Monroe testified that "the Company will still be required to invest in the yet to be decommissioned river hydroelectric facilities to maintain safety, a process

that will take over 20 years to complete." 5 TR 2390. The Company may yet be able to mitigate or avoid some of these future decommissioning-related issues, but not if the proposed disallowances are adopted in this case.

Mr. Monroe also explained that IRRMs are not a viable alternative to completing the planned investments for the River Hydro plants. Mr. Monroe testified that IRRMs are intended to act as temporary or interim measures until such time when more permanent remediation measures can be effectively implemented. 5 TR 2391. However, he explained that a critical project, like the Hardy spillway project, should not be delayed further. 5 TR 2391. Mr. Monroe points to recent extreme weather events across the United States and notes several dams that experienced serious detrimental and safety-related impacts as a result of those larger-flow events. See 5 TR 2392; Exhibit A-253 (AJM-8). He explained that he has participated in conversations with FERC on the Hardy Spillway Project specifically and that FERC views its licensure of that plant to require the project to be completed regardless of the funding approval process. 5 TR 2392. Delaying these projects puts FERC license compliance and the long-term safety of the structures at risk. 5 TR 2394. Mr. Monroe testified that FERC's approval of the Hardy Spillway Project is expected by the end of 2024 with mobilization to the site in June of 2025 and the start of construction in September 2025. 5 TR 2391. The project is required to eliminate the current significant risk, expected by FERC, and progressing rapidly. Short-term interim measures are just not viable at this point.

Similarly, ABATE's claims that the Company may be awarded certain grants from the U.S. Department of Energy do not support a proposed disallowance. Company witness Blumenstock testified that the Company has not been awarded a grant, explaining that the Company has only been offered an opportunity to negotiate with the U.S. Department of Energy for financial

assistance awards. 5 TR 1527. Furthermore, he explained that the Commission approved accounting authority in Case No. U-21494 which allows the Company to utilize a regulatory asset or liability to defer recovery or refund for expenses above or below amounts approved in rates for certain projects related to funding from the federal IIJA. 5 TR 1527. Mr. Blumenstock stated, "As such, to the extent that the Company does ultimately receive IIJA funding as well as rate recovery of certain project investment, the Company's customers will be made whole through the reconciliation of the regulatory account." 5 TR 1527. The Commission has already made provision to ensure that customers are held harmless for any expenditures corresponding to grant funding the Company may potentially receive, so the possibility of potential grants is not a valid reason to withhold needed rate recovery.

Furthermore, Mr. Monroe notes that, although the Company forecasts significant bridge period and test year spending for the Hardy projects in this case, those project costs are subject to an AFUDC offset because they are not scheduled to be complete until after the end of the test year. 5 TR 2394. That means that they do not contribute to any increase in the revenue requirement in this case. 5 TR 2394. If the Commission adopts the proposed Hardy disallowances in this case, it will not reduce the revenue requirement presented by the Company, but it would force the Company to cease investment in those projects, thereby placing the Company's FERC license in jeopardy. 5 TR 2389. Once again, the Company must have assurance of cost recovery for these projects in order to proceed with investments of this magnitude. The Company needs to know in this case that the Commission recognizes the need for the work and that the Commission plans to support it with appropriate ratemaking in a future case before the Company can proceed with the River Hydro investments. The best and most appropriate course of action given the legitimate need for these investments even if the Company ultimately sells the River Hydro facilities is for

the Commission to approve the Company's planned expenditures during the bridge period and test year in this case, with the understanding that the rate impact of those expenditures will occur in a future electric rate case when those investments are put into service. As long as the Company is the FERC-licensed owner and operator of 13 River Hydros, Consumers Energy has the responsibility to safely and reliably operate these assets in compliance with FERC regulations and approved licenses. 5 TR 2384. The Commission should expressly confirm that fact through its final order in this case.

Nevertheless, because the Company appreciates the difficulty of this situation, Consumers Energy proposes an alternative that the Commission could consider instead of the binary choice between approval or disallowance. The Commission could authorize the Company to record the revenue requirement of actual spending for the River Hydros for the bridge period and test year to a regulatory asset until the determination of the future of the River Hydros is certain and base rates are set to appropriately include actual spending. 5 TR 2390-2391. That would allow the Company to continue to invest, as necessary, to support safety, reliability, and regulatory compliance while ensuring that customers are not asked to support spending that does not actually occur. 5 TR 2390. This alternative keeps all of the options open while protecting customers and should be adopted by the Commission instead of disallowances if the Commission is unwilling to approve the capital investments needed in the bridge period and test year for the River Hydro plants at this time.

Finally, if the Commission decides to adopt Staff's disallowances solely for the Hardy projects (which it should not), the Commission must correct the double-counting of the disallowances proposed by Staff witnesses DeCooman and Bodiford. Mr. Blumenstock explained that Mr. Bodiford's proposed class estimate disallowances include a proposed disallowance of $5.495 million for the Hardy Auxiliary Spillway Replacement project and a proposed disallowance

of $0.276 million for the Hardy Splash Wall Replacement project despite the fact that Mr. DeCooman also proposes a complete disallowance of each of these projects. 5 TR 1537. Both of these disallowances for the same investment are included in Staff's worksheets presenting Mr. Bodiford's and Mr. DeCooman's adjustments which were provided by Staff in its response to the Company's third discovery request. 5 TR 1537. To the extent that Mr. DeCooman's proposed disallowances are approved by the Commission, Mr. Bodiford's proposed disallowances should not be considered as that would constitute double counting. 5 TR 1537.

For all of the reasons discussed above, the Commission should reject the proposed disallowances for the Company's River Hydro investments in the bridge period and test year proposed by Staff witness DeCooman, Attorney General witness Deupree, and ABATE witness York. The Commission should instead approve all of the Company's proposed capital investments in this case for the River Hydro plants with the adjustments for updated cost estimates shown in Staff's Exhibit S-16.1. In the alternative, the Commission should approve the regulatory asset proposed by Company witness Monroe. In either case, it is vital that the Commission affirm the importance of the work the Company plans to do at its River Hydro plants for the safety of the communities near those plants and for compliance with FERC's licensing requirements. The Commission's reasonable forbearance and cooperation will keep all of the options open for the very short time remaining until the Company is able to complete its full evaluation and determine the one that will provide the best outcome for customers and the impacted communities. That decision is imminent and expected in just a few short months during the first quarter of 2025.

d. The Commission Should Adopt Staff's Proposal to Move the Company's Solar Generation Capital Expenditures from this Case to the Company's Renewable Energy Plan Case

References in the Record: Clark, 5 TR 1598-1599, 1624, 1627, 1629, 1633, and 1655-1657, Exhibit A-190 (TPC-8); Blumenstock, Exhibit A-12 (RTB-3), Schedule B-5.2; Harlow, 5 TR 3684-3688; Deupree, 5 TR 2914-2919

Consumers Energy witness Clark, Executive Director of Clean Energy Project Development, testified to the costs associated with the Company's new solar generation projects. Specifically, Mr. Clark supported the costs related to: (i) Mustang Mile Solar, a 150 MW solar generation facility in Lenawee County; (ii) Washtenaw Solar, a 150 MW solar generation facility located in Washtenaw County; (iii) Muskegon Solar Energy Center, a 250 MW solar generation facility located in Muskegon County; and (iv) Spring Creek Solar, a 140 MW solar generation facility located in Calhoun and Barry Counties. 5 TR 1598-1599. These projects were selected as the result of annual competitive solicitations approved as part of the Company's 2018 and 2021 IRPs. 5 TR 1624, 1627, 1629, and 1633. The Company originally requested Commission approval to include investments totaling $249.572 million for the bridge period and $275.959 million for the test year for these solar projects. See Exhibits A-190 (TPC-8) and A-12 (RTB-3), Schedule B-5.2, page 2, line 50.

Staff witness Harlow testified that the Governor approved Public Act 235 of 2023 ("PA 235") in November 2023, which increases each electric providers' renewable energy portfolio requirement to 50% by 2030 and 60% by 2035. 5 TR 3685. He explained that PA 235 includes a cost recovery methodology substantially similar to the methodology applicable to renewable energy resources under Public Act 295 of 2008 ("PA 295"). 5 TR 3685. Mr. Harlow testified that, to his knowledge, the costs for all of Consumers Energy's existing renewable energy generation facilities have been recovered (and continue to be recovered) through the cost recovery methodology under PA 295 and none of those costs are being recovered through base rates. 5 TR

3685. Mr. Harlow recommends that the Commission remove all of the investments for Mustang Mile Solar, Washtenaw Solar, Muskegon Solar, and Spring Creek Solar from this case so that they can be moved to the Company's Renewable Energy Plan Amendment. 5 TR 3684. Mr. Harlow reasons that, with the significant increase in renewable energy resources required by PA 235, these four solar facilities will now be needed to meet the requirements of the new law. 5 TR 3686. He argues that it is appropriate to address cost recovery for all renewable energy resources using the cost recovery mechanism of PA 235 in order to keep all of those similar resources in one proceeding and to reduce the chance for errors. 5 TR 3687.

Consumers Energy agrees with Staff's recommendation and supports the removal of the costs for Mustang Mile Solar, Washtenaw Solar, Muskegon Solar, and Spring Creek Solar from this case. Clark, 5 TR 1655. Instead, the Company has included those costs in its Renewable Energy Plan Amendment filed in Case No. U- 21816 on November 15, 2024. However, Consumers Energy reserves the right to include these costs in a future electric rate case if the Commission later determines that they should not be included in the Renewable Energy Plan Amendment. 5 TR 1655. Consumers Energy submits that the Commission should be clear in its final order in this case that removal of the investments from this case is not a determination that those investments are being disallowed as unreasonable or imprudent for future rate recovery. 5 TR 1655.

Attorney General witness Deupree also recommended that the Commission remove all of the capital associated with the Company's Washtenaw Solar, Muskegon Solar, and Spring Creek Solar projects from this case. 5 TR 2914. He argues that the expected completion dates of the projects have been delayed or that they are otherwise premature for inclusion in rates. 5 TR 2914-2919. Company witness Clark testified that Consumers Energy disagrees with the Mr. Deupree's

reasons, but notes that the Company has already agreed to Staff's proposal to remove all of the solar investments from this case. 5 TR 1657. The Attorney General's recommendation should be treated as moot in light of the Company's agreement to move the costs of these solar projects out of this case and into the Renewable Energy Plan Amendment.

On a related side issue, Staff witness Harlow also recommended that the Company "file for approval of any of these contracts and all supporting information for the four projects, referenced in my testimony, that have not already been approved in its most recent IRP docket in Case No. U-21090, as soon as possible, with all the information so that Staff may then conduct its contract review." 5 TR 3688. He also recommended that Renewable Portfolio Standard compliant projects should be filed for approval as a stand-alone application "in the most recent Renewable Plan application filing." 5 TR 3688. For purposes of Mr. Harlow's first recommendation, the only two projects that have not previously been approved in some type of filing with the Commission are the Muskegon Solar project and the Spring Creek Solar project.

Consumers Energy disagrees with Mr. Harlow's first recommendation because it is inconsistent with the legal framework for Commission review and approval of cost recovery for such projects. As Mr. Clark testified, aside from specific projects included in the first three years of an IRP, there are generally three paths for the Commission to review and approve the reasonableness and prudence of a utility-developed generation project for purposes of cost recovery: (i) a Certificate of Need ("CON") case; (ii) a general rate case; or (iii) a Renewable Energy Plan case. 5 TR 1656. The Company's Spring Creek Solar project and Muskegon Solar project do not satisfy the threshold requirements for a CON filing. 5 TR 1656. That leaves a general rate case or a Renewable Energy Plan case as appropriate options for Commission review. Given that the Company has agreed to move the Spring Creek Solar and Muskegon Solar projects

from this general rate case to its Renewable Energy Plan Amendment, Mr. Clark explains that the Renewable Energy Plan Amendment is the appropriate proceeding for the Commission to consider the contracts and other supporting documents associated with these projects. 5 TR 1656. Nevertheless, Mr. Clark committed that the Company would be willing to share the contracts and supporting documents that it has available for these projects or any future Company-developed generation projects that result from the IRP's competitive solicitation process with Staff in advance of submitting the project to the MPSC for cost-recovery approval in one of the appropriate proceedings discussed previously. 5 TR 1656. In fact, this issue is also moot now in light of the fact that Consumers Energy filed its Renewable Energy Plan Amendment on November 15, 2024 in Case No. U-21816. That filing contains the information Staff requested. In terms of Staff's second recommendation, that is consistent with Consumers Energy's plans for how to address such projects going forward.

e. The Commission Should Approve the Company's BESS Capital Expenditures

The development and deployment of battery systems are a fairly new, but rapidly expanding, part of the electric utility industry. Battery systems have the potential to address a variety of different needs and opportunities related to both the generation and distribution functions of the utility. Consumers Energy's current investments in battery systems fall into two programs: (i) the IRP BESS 75 MW Deployment Program; and (ii) the Grid Storage Program. Each of those programs and the Company's related projects are described in more detail below.

i. IRP BESS 75 MW Deployment Program

a) The Company's Planned Investments for the Weadock and Iosco BESS Projects are Reasonable and Prudent

References in the Record: Clark, 5 TR 1636-1642, 1661-1663

In Case No. U-21090, as part of the 2021 IRP Settlement Agreement, the Company agreed to issue a competitive solicitation to implement batteries on its distribution system. Clark, 5 TR 1636. Paragraph 3 of the 2021 IRP Settlement Agreement in Case No. U-21090 specifically stated:

> The parties agree to the approval of the battery deployment program as proposed by Company witness Richard T. Blumenstock. The parties agree that the Company will conduct stakeholder outreach to solicit feedback regarding the battery deployment program prior to the issuance of the first battery deployment program competitive solicitation. The approval to recover the costs associated with the batteries acquired in the battery deployment program will be sought in future electric rate cases. [5 TR 1636-1637.]

In that proceeding, in Company witness Blumenstock's rebuttal testimony, the Company agreed that pulling the storage glide path forward to 2024 would provide opportunity for the Company to provide localized grid support and provide data regarding how battery storage could aid in achieving a 2040 net-zero target. 5 TR 1637. The Company indicated that it would add 75 MW of batteries between 2024 and 2027. 5 TR 1637.

After entering into the settlement, the Company conducted a stakeholder outreach session on August 17, 2023. 5 TR 1639; Exhibit A-198 (TPC-16). After receiving feedback on its proposed solicitation, on September 30, 2022, the Company issued a solicitation to 21 companies seeking up to 75 MWs of BESS to be deployed in accordance with the schedule shown on Table 9 of Mr. Clark's testimony. 5 TR 1639; Table 9 appears on 5 TR 1637. The Company received bids from five companies. 5 TR 1639. After an evaluation, the Company determined that the bids were not economic, and they were released. 5 TR 1639.

Based on the lessons learned from the first battery solicitation, Consumers Energy issued a repackaged RFP on June 27, 2023, with the objective of obtaining more economic results. 5 TR 1640. Based on its learnings, the new RFP eliminated uncertainty in location, timing, and project specific requirements. 5 TR 1640. As a result, the second battery solicitation resulted in two successful bids for (i) the Weadock BESS project and (ii) the Iosco BESS project.

The Weadock BESS project is a 45 MW/180 MWh lithium-ion battery energy storage system interconnected at the Weadock Substation on the Consumers Energy 46 kV HVD system located in Bay County. 5 TR 1640. The purpose of this project is to provide localized grid support and provide data regarding how battery storage could benefit the reliability, resiliency, and performance of the HVD system as well as provide energy arbitrage and firm dispatchable capacity in the MISO market. 5 TR 1640. This project will be constructed on Company-owned property within the Karn/Weadock Generating complex. 5 TR 1640. When the Company originally filed this case, the project was scheduled to begin commercial operation on December 1, 2025. 5 TR 1641. During the course of this case, the commercial operation date for the project changed to December 2026. 5 TR 1662. The Company also originally projected that it would spend $19.750 million in the bridge period and $44.180 million in the test year for the Weadock BESS project. 5 TR 1641. The Company's updated estimates are for capital investments of $19.575 million for the bridge period and $36.682 million for the test year. 5 TR 1663.

The Iosco BESS project is a 30 MW/120 MWh lithium-ion battery energy storage system interconnected at the Iosco Substation on the Consumers Energy 46 kV HVD system located in Iosco County. 5 TR 1642. The purpose of this project is to provide localized grid support and provide data regarding how battery storage could benefit the reliability, resiliency, and performance of the HVD system as well as provide energy arbitrage and firm dispatchable capacity

in the MISO market. 5 TR 1642. This project will be constructed on existing Company-owned property near the existing Iosco Substation. 5 TR 1642. When the Company originally filed this case, the Iosco BESS project was scheduled to begin commercial operation on November 10, 2025. 5 TR 1642. During the course of this case, the commercial operation date for the project changed to December 2026. 5 TR 1661. The Company also originally projected that it would spend $15.590 million in the bridge period and $29.870 million in the test year for the Iosco BESS project. 5 TR 1643. The Company's updated estimates are for capital investments of $14.612 million for the bridge period and $24.873 million for the test year. 5 TR 1661.

The Weadock and Iosco BESS projects are the product of a careful and thoughtful competitive solicitation process, which the Company pursued consistent with its Commission-approved IRP. When the original solicitation results failed to produce economic projects that would benefit customers, the Company went back to try again until it was able to acquire economically beneficial projects. The Company has continued to update and refine its project estimates, even as this case has been ongoing, to ensure that the case includes the most accurate information about these innovative projects. Battery technology will be an important part of the Company's portfolio in the future, and it is important for the Commission to continue its support for the development of this technology. For all of these reasons, the Company's planned investments for these projects are reasonable and prudent and should be approved in this case.

b) <u>The Commission Should Reject the Attorney General's Proposed Disallowances for the Weadock and Iosco BESS Projects</u>

References in the Record: Deupree, 5 TR 2923-2924; Clark, 5 TR 1660-1663

Attorney Geneal witness Deupree recommended that the Commission disallow all of the Company's planned capital investments for the Weadock and Iosco BESS projects solely on the basis that the projects would not be completed until after the conclusion of the test year in this

case. 5 TR 2923-2924. That is not a proper basis for disallowance of these reasonable and prudent investments. Company witness Clark noted that no party (including the Attorney General) challenged the reasonableness and prudence of these projects. 5 TR 1661, 1663. Indeed, the Company's pursuit of these projects was explicitly agreed upon as part of the settlement of the Company's last IRP case. The Company agrees with Mr. Deupree that these projects will no longer be in service before the end of the test year. 5 TR 1660, 1662. However, contrary to the Attorney General's recommendation, the correct ratemaking treatment for any capital investments that are AFUDC eligible and will not be put into service before the end of the test year is to include those projects in Construction Work in Progress ("CWIP") in the rate case and apply an AFUDC offset. The updated revenue requirement supported in the Company's rebuttal testimony in this case correctly applies an AFUDC offset to these projects to reflect the fact that they will not be in service during the test year. 5 TR 1660, 1662. Company witness Clark testified: "As a result, effective with the Company's rebuttal revenue deficiency as filed by Company witness Myers, this project has no impact on the revenue requirement requested in this case, and there is no reason to disallow any portion of the completed or planned investments for this project." 5 TR 1660-1661, 1662. Disallowance is unnecessary and would only serve to further delay the projects and likely increase the cost of projects. 5 TR 1661-1663. The Commission should reject the Attorney General's proposed disallowance and approve the updated cost estimates supported by the Company in its rebuttal testimony.

ii. Grid Storage Program

a) The Company's Planned Investments for the Armstrong BESS Project are Reasonable and Prudent

References in the Record: Clark, 5 TR 1643-1649, 1658-1659, Exhibit A-234 (TPC-24)

Since battery systems are a new technology for the Company, deploying energy storage on the grid involves major organizational and operational challenges. 5 TR 1644. Company witness Clark testified that planning, modeling, engineering, installing, and operating energy storage requires a new set of skills and tools that are different from those that have been used historically. 5 TR 1644. Consumers Energy's Grid Storage Program represents the Company's initiative to develop a knowledge base through the deployment of small-scale storage projects to facilitate and expedite the Company's learning in support of this new technology. 5 TR 1644.

Mr. Clark explained that storage can play a key role in maintaining demand-generation balance in regions with high penetration of renewables. 5 TR 1643. Energy storage can capture surplus solar and wind generation during periods of low demand and inject it into the grid during high demand when the sun is not shining, and the wind is not blowing. 5 TR 1643. Storage can also fill in gaps in renewable generation output caused by passing clouds and irregular wind patterns, stabilizing the supply to the grid. 5 TR 1643-1644. In addition, as decarbonization goals in the energy sector become more prominent, storage can play a key role in supporting the grid as fossil generation plants retire. 5 TR 1644. Mr. Clark testified that, in standalone use cases, energy storage can support the existing distribution infrastructure by adding capacity to avoid upgrades, by improving distribution resiliency and reliability through islanding applications, and by adding system inertia to minimize undesirable voltage and frequency excursions from varying demands and generation levels. 5 TR 1644.

The knowledge and experience gained in the Grid Storage Program's small-scale deployments are increasingly relevant as more opportunities develop for storage through market and regulatory forces. 5 TR 1644. In addition, as the Company seeks to achieve its clean energy ambitions as identified in its most recent IRP, acquiring this experience is a key necessity. 5 TR 1644. The Armstrong BESS Project is the Company's principal initiative in the Grid Storage Program.

Under the Armstrong BESS Project, Consumers Energy will install a 3.5 MW/11.5 MWh battery on the distribution system located in Calhoun County. 5 TR 1646. The purpose of this project is to explore how to use an islanded battery to quickly restore power to unfaulted sections of the distribution system, while the faulted zones upstream on the distribution system are being restored. 5 TR 1646. This project will provide insights into designing a protection system capable of operating under normal and reduced fault current scenarios and about other operation requirements associated with using a battery and a NWS. 5 TR 1646. Through the Armstrong BESS Project, the Company will be able to study, develop, and test in a more controlled distribution environment; a primary protection system capable of operating safely and independently under both utility as well as islanded inverter-based generation conditions. 5 TR 1647. This will help set the technical basis for designing and deploying future storage to reduce outages on sections of the distribution system. 5 TR 1647.

By installing the Armstrong BESS Project, the Company projects a reduction of 286 outage minutes (90% improvement) annually for the large commercial customer who is working with the Company in testing this use case. 5 TR 1648. More important, however, is that this project will lead the Company to develop the skillset needed to extend this islanding use case to sections of the distribution system, where multiple customers can be served from an islanded battery during

upstream line or substation outages. 5 TR 1648. For the Company to learn how to safely and effectively implement battery storage to reduce avoidable outage minutes for the customers, it is imperative to begin the deployment and testing of these storage applications now. 5 TR 1648. Other options considered do not provide the Company the same learning and experience. 5 TR 1648-1649.

In the Company's last electric rate case, the Commission approved the Company's capital investments for the Armstrong BESS Project. See U-21389 Order, pages 74-75. The Commission agreed that the learnings the Company will obtain through the project will be of benefit to customers and that investment needed to begin now in order to facilitate lessons that may be useful to using batteries to reduce avoidable outage minutes for customers. *Id*. The Commission also recognized that the Company had executed a contract for the project, secured a 30-year easement on property owned by the City of Battle Creek, and made other investments. *Id*. See also 5 TR 1646. The Commission concluded that these factors supported approval of the capital for this project.

Progress on the project has continued. The Armstrong protection study was completed on March 21, 2024. 5 TR 1647. Upon completion of the protection scheme work, the Company engaged internal departments, including IT and Security, to develop necessary scopes of work. 5 TR 1658. The Company leveraged these scopes of work to obtain quotes for a BESS Integrator, an Engineering/Procurement/Construction ("EPC") Contractor, Protections Relay Engineering Support, an Owner's Engineer, and Investment Tax Credit Compliance Support. 5 TR 1658. The Generator Interconnection and Operating Agreement ("GIOA") process was concluded, with full execution of the GIOA occurring in September. 5 TR 1658. Consumers Energy held discussions with the local authority having jurisdiction to review the site plan. 5 TR 1658. The Company

updated the project budget based on the quotes collected and cost data from various supporting groups. 5 TR 1658. Finally, the project schedule was updated, informed by data from other BESS projects and supporting groups. 5 TR 1658-1659. In short, this project continues advancing, and the Company has already performed substantial work toward its completion. When this case was originally filed, final commissioning for the project was planned for the first quarter of 2026. 5 TR 1647. Based on the Company's updated schedule completed in light of the work discussed above, the Company now expects the project to be in service in December 2026. Exhibit A-234 (TPC-24).

The Company originally projected investments of $3.931 million in the bridge period and $4.879 million in the test year for the Armstrong BESS Project. 5 TR 1649. Due to the change in timing to complete the project and other more up-to-date information available to the Company, the Company updated its cost estimate in rebuttal. The Company now projects that it will invest $2.730 million in the bridge period and $11.304 million in the bridge period on the Armstrong BESS Project. 5 TR 1659. Mr. Clark explained that the direct engagement of battery manufacturers and EPC contractors makes the current cost estimate and schedule much more certain than earlier cost and schedule estimates. 5 TR 1659. The Company's planned investments for the Armstrong BESS Project are reasonable and prudent and should once again be approved by the Commission.

b) <u>The Commission Should Reject the Disallowances Proposed by Staff and the Attorney General</u>

References in the Record: DeCooman, 5 TR 3672-3674; Deupree, 5 TR 2923; Clark, 5 TR 1657-1661

Staff witness DeCooman recommended that the Commission disallow all bridge period and test year spending in this case for the Armstrong BESS Project. 5 TR 3673. Mr. DeCooman argued that Staff's concerns from Case No. U-21389, specifically Staff's claim that the project has limited benefits to customers compared to costs, "remains largely unresolved." 5 TR 3674. Staff

notes that this is particularly true since none of the costs will be offset by federal grants after the Company's previously pending grant application was not selected. 5 TR 3673-3674. Mr. DeCooman also discusses the delays in project completion due to the Armstrong protection study taking longer than originally expected to be completed. 5 TR 3672.

The Commission should once again reject Staff's recommended disallowance. Staff witness DeCooman himself acknowledges that "[t]he information presented in this case to support Armstrong is largely the same as what was presented in the Company's previous electric rate case, Case No. U-21389." 5 TR 3674. The Commission specifically found that "Consumers [Energy] provided sufficient evidence on this record of the potential benefits that could accrue from the Armstrong BESS including how to use an islanded battery to restore power." U-21389 Order, page 74. If the evidence was sufficient in Case No. U-21389, just eight months ago, it stands to reason that the same evidence remains sufficient to support the benefits of the project today. The Commission's Order in Case No. U-21389 also directly addressed Staff's concerns about the relative cost of the Armstrong BESS Project compared to the direct monetary benefits to be gained. The Commission wrote: "The Commission reiterates that while full implementation of a pilot at scale is strengthened by showing a positive BCA [Benefit-Cost Analysis] and a benefit to all ratepayers, implementation of the pilot itself does not need to be accompanied by the same showing . . . ." *Id*. The Armstrong BESS Project is meant to provide information and experience that can be used to evaluate when it is economically feasible and justifiable to replicate similar projects across the Company's system in the future. The Commission correctly understood that without trying new things, the Company will never gain new skills and will perpetually miss opportunities to adopt new technologies that may benefit customers after some trial and experimentation.

Company witness Clark responded that "Mr. DeCooman's cost-benefit assessment overlooks the value that this project will provide customers by allowing the Company to develop the necessary expertise to effectively plan and deploy battery-supported microgrids." 5 TR 1657. He explained that the Company considers this sought-after expertise an essential element to guarantee that future distribution microgrids operate as designed, meet planned reliability goals, and reduce the cost and impacts of future outages. 5 TR 1657. According to Mr. Clark, failure to acquire this expertise will prevent the Company from deploying this distribution resource in the future due to the increased safety risks associated with the protection requirements of battery-supported microgrids. 5 TR 1657-1658. Eliminating this risk from future microgrid projects and enabling broader deployment of this technology are a highly valuable benefit to all customers. 5 TR 1658. Staff's concerns about the benefits of this project relative to its cost have already been considered and rejected by the Commission.

It is also important to note that the most recent forecast regarding the Armstrong BESS Project's in-service date places it beyond the end of the test year in this case. As a result, Mr. Clark explained that the revenue requirement associated with those expenditures is now offset by AFUDC. 5 TR 1659. The Company has reflected the reduction associated with this change in its rebuttal revenue deficiency as filed by Company witness Myers. 5 TR 1659. Therefore, this project has no impact on the revenue requirement requested in this case, and there is no reason to disallow any portion of the completed or planned investments for this project. 5 TR 1659. The Commission should decline to adopt Staff's proposed disallowance and approve the revised bridge period and test year capital investments supported in Mr. Clark's rebuttal testimony.

Attorney General witness Deupree also recommended that the Commission disallow all of the Company's planned investment for the bridge period and test year for the Armstrong BESS

Project. 5 TR 2923. Mr. Deupree's only reasoning was that the project will not be in service until after the end of the test year. 5 TR 2923. But, once again, that does not provide a valid basis for disallowing reasonable and prudent Company investments. As the Company discussed above in response to Staff, the Armstrong BESS Project investments are now AFUDC eligible. The correct ratemaking treatment when a project is not expected to be in service before the end of the test year is to include the project in CWIP and apply an AFUDC offset, which removes the revenue requirement of the project from the case. Clark, 5 TR 1660. That is what the Company has done with the Armstrong BESS Project investments in the rebuttal revenue deficiency calculation. 5 TR 1660-1661. The Commission should reject the Attorney General's proposed disallowance.

f. Decommissioning and Coal Ash Disposal

References in the Record: Koetje, 5 TR 1978, 1981-1999, Exhibits A-120 (JJK-1), A-122 (JJK-2), and A-123 (JJK-3)

Company witness Jon J. Koetje testified in support of the Company's actual and projected costs for decommissioning Karn Units 1 and 2 and Campbell Units 1, 2, and 3, as well as the Company's actual and projected costs for coal ash disposal for Karn Units 1 and 2, Campbell Units 1, 2, and 3, and the so-called Classic 7[7] sites. 5 TR 1978. In Case No. U-20849 (the Company's last electric depreciation case), the Commission approved a settlement agreement among the parties that removed the Karn Units 1 and 2 decommissioning costs and the coal ash disposal costs from the Company's depreciation rates, where they would ordinarily be reflected. 5 TR 1981. Instead, the parties to that case (and the Commission through its order) agreed that the

[7] The Classic 7 plants refer to the seven electric generation plants Consumers Energy retired in 2016, which includes three units at the J.R. Whiting ("Whiting") Generating Complex near Luna Pier; two units at the B.C. Cobb ("Cobb") Generating Plant in Muskegon; and two units at the Karn/J.C. Weadock ("Weadock") Generating Complex near Bay City. 5 TR 1979.

costs would be recorded, as spent, to a regulatory asset, which may be recovered in future rate cases. 5 TR 1981.

The Commission-approved settlement agreement in Case No. U-20849 also specified that the Company would file its plans for decommissioning and ash disposal costs for Karn Units 1 and 2 and its plans for ash disposal costs for the Classic 7 prior to spending any costs recordable to the regulatory asset in the Company's next electric rate case. The Company presented its plans for the decommissioning and coal ash disposal costs for Karn Units 1 and 2 and its coal ash disposal cost for the Classic 7 in Case No. U-21224. 5 TR 1981. The Commission-approved settlement agreement in that proceeding approved the Company's plans for decommissioning of Karn Units 1 and 2 and coal ash disposal costs for Karn Units 1 and 2 and the Classic 7. 5 TR 1981-1982. The Company updated its plans in Case No. U-21389. 5 TR 1982.

Similarly, the Commission-approved settlement agreement in the Company's 2021 IRP in Case No. U-21090 provided for the recovery of actual decommissioning and coal ash disposal spending for Campbell Units 1, 2, and 3. 5 TR 1997. The IRP settlement provided for the Company to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, and also provided for rate recovery to occur in future rate cases after a review of the reasonableness and prudence of the expenditures. 5 TR 1997. Details regarding the treatment of these regulatory assets are discussed in a later section of this Initial Brief. This section of the Company's Initial Brief describes the actual and projected costs as required by the settlement agreements in Case Nos. U-20849 and U-21090.

With respect to the decommissioning of Karn Units 1 and 2, Mr. Koetje testified that Consumers Energy retired the plants on May 31, 2023. 5 TR 1983. He explained that the decommissioning plan involves numerous activities, including:

> [S]takeholder engagement, workforce and community transitions, future use analysis, divestiture analysis, physical transition of systems to a de-energized state, remediation of regulated materials, physical demolition of the plant assets, salvage of scrap metals, remediation of all impacted areas, backfill of soils to acceptable engineered specifications, restoration focused on maximizing redevelopment opportunities, and completion of project closure to a brownfield standard. [5 TR 1983.]

To complete those decommissioning activities, the Company has identified necessary spending in eleven specified categories of costs: (i) Utility Separation; (ii) Decommissioning; (iii) Abatement; (iv) Demolition; (v) Asset Recovery; (vi) Environmental; (vii) Restoration; (viii) Inventory Write Off; (ix) Contingency; (x) Project Indirects; and (xi) Interim Cost of Removal ("COR"). 5 TR 1984.

Mr. Koetje testified that actual costs for decommissioning at Karn Units 1 and 2 totaled $24.895 million in 2023. 5 TR 1985; Exhibit A-120 (JJK-1), column (e), line 11.[8] The Company incurred actual costs in all of the cost categories described above except abatement, restoration, and contingency. See 5 TR 1986-1992; Exhibit A-120 (JJK-1), column (e). The Company is presenting an updated decommissioning plan for Karn Units 1 and 2 in this case, as permitted by the settlement agreement in Case No. U-20849. In addition to showing the actual costs for 2023, Exhibit A-120 (JJK-1) shows the updated projected costs of the decommissioning activities over the next several years (to 2026). Mr. Koetje projects that the Company will spend approximately $41.0 million in 2024, $8.9 million in 2025, and $5.0 million in 2026 for a combined total projected spend (including 2022 and 2023 actuals) of $90.528 million for the Karn Units 1 and 2 decommissioning efforts. 5 TR 1984, Table 1.

[8] The exhibit inadvertently has two lines labeled as "11." This Initial Brief refers to the bottom line, which represents the total of all decommissioning expenditures.

Mr. Koetje explained that three main developments impacted the projected costs for decommissioning Karn Units 1 and 2 compared to the decommissioning plan filed in Case No. U-21389. 5 TR 1986. First is the transition to Class 2 cost estimates with definitive bids for the main abatement and demolition work scope. 5 TR 1986. Second is the mitigation of risk as the project has progressed. 5 TR 1986. Third is that the Company discovered that a portion of the work within the original scope of the Decommissioning estimate for Utility Separation relates to functional assets required for the continued operation of Karn Units 3 and 4. 5 TR 1986. Mr. Koetje explained that those types of costs cannot properly be characterized as decommissioning. 5 TR 1986. Overall, the Company's updated plan reflects a cost decrease of $6.527 million compared to the plan presented in Case No. U-21389. 5 TR 1985. Mr. Koetje explains the updates for each cost category in his testimony. 5 TR 1986-1992.

With respect to the coal ash disposal costs for Karn Units 1 and 2 and the Classic 7, Mr. Koetje explained that the Company's remaining coal ash disposal costs consist of: (i) long-term groundwater monitoring at Karn, Weadock, Cobb, and Whiting; (ii) closure construction activities consisting of construction of a remedial response for the Karn Landfill; (iii) installation of a final cover system to close the Weadock Landfill; and (iv) closure certification of the Cobb Ash Ponds 0-8 and Bottom Ash Pond. 5 TR 1993. The Company's coal ash closure plans must conform to new U.S. EPA requirements and are subject to oversight and approval by the Michigan Department of Environment, Great Lakes, and Energy. 5 TR 1992-1993.

Mr. Koetje testified that actual costs for coal ash disposal for Karn Units 1 and 2, Campbell Units 1, 2, and 3, and the Classic 7 for 2023 totaled $18.273 million. 5 TR 1993; Exhibit A-121 (JJK-2). This was less than the projected amount of $32.372 million in Case No. U-21389 for 2023. Exhibit A-121 (JJK-2). Mr. Koetje testified that the Company's projected coal ash disposal

costs for the remainder of the period forecasted in Case No. U-21224 have not changed. 5 TR 1993. Mr. Koetje also explained that the Company continues to be subject to environmental regulations that will require the Company to make additional capital expenditures for historical ash closures, groundwater conditions, and effluent treatment, as well as ongoing capital expenditures for maintenance of previously installed equipment. 5 TR 1996. He cautions that Consumers Energy will likely continue to incur costs to comply with the known and unknown environmental conditions in the future. 5 TR 1996.

Finally, Mr. Koetje sponsored Exhibit A-122 (JJK-3), which shows the actual Campbell decommissioning costs incurred in 2023. Mr. Koetje testified that the Company incurred a total of $15.353 million of decommissioning expense to the regulatory asset related to Campbell Units 1, 2, and 3 in 2023. 5 TR 1998. Mr. Koetje explained that the project expenditures in 2023 included $6.688 million for Engineering & Supervision, Other Post-Employment Benefits, Pension, and Administrative & General costs, and $8.665 million in Interim COR as the result of writing off the cost of projects that were initiated prior to the decision to decommission and will not be completed before the cessation of operations. 5 TR 1998-1999.

Mr. Koetje testified that the decommissioning costs and coal ash disposal costs presented in his testimony for Karn Units 1 and 2, Campbell Units 1, 2, and 3, and for the Classic 7 were reasonably and prudently incurred. 5 TR 1999. No party in this case submitted any testimony challenging any aspect of the Company's actual or projected costs for decommissioning or for the coal ash disposal. Therefore, the Commission should accept the Company's actual and projected costs as reasonable at this time.

4. Operations Support Capital Expenditures

References in the Record: Guinn, 5 TR 1799-1844; Exhibit A-12 (QAG-1), Schedule B-5.4

Operations Support acquires, constructs, and maintains the Company assets required to operate the functional areas of the business. This consists of (i) Fleet Services, (ii) Facilities, (iii) Real Estate, and (iv) Administrative Operations. 5 TR 1801. Fleet Services is addressed separately below.

The Company's Operations Support capital expenditures are broken down into two cost categories -- Asset Preservation and Other Equipment. 5 TR 1807. Other Equipment includes capital investments for wellness equipment; computer equipment; print equipment; Real Estate organization tools and equipment; Supply Chain organization tools and equipment; and Facilities organization tools. 5 TR 1808. As shown in Exhibit A-12 (QAG-1), Schedule B-5.4, the Company's Other Equipment projected test year spending is $688,000. 5 TR 1808.

Investment in Asset Preservation of the Company's facilities generally includes investment in new construction, remodeling of existing facilities, emergent work, lifecycle replacement of infrastructure equipment, and system failures. These investments are typically broken into four categories: (i) emergent repairs; (ii) asset replacement; (iii) new construction; and (iv) renovations. 5 TR 1807. Projects which support these components of Asset Preservation expenditures are described at 5 TR 1809-1837. As shown in Exhibit A-12 (QAG-1), Schedule B-5.4, the Company's Asset Preservation projected test year spending is $26,083,000. The Company's proposed Asset Preservation projects were identified in Exhibit A-82 (QAG-3). The disputed expenditures are discussed below.

a. Lansing Service Center

References in the Record: Guinn, 5 TR 1812-1820, 1841-1842; Exhibit A-82 (QAG-3); Deupree, 5 TR 2924-2926

The Lansing Service Center Project is a multi-year project that was approved by the Commission in Case No. U-20963. For this project, the Company has purchased land in a new location and will construct a new facility on that property. Specifics regarding the reasons for replacement of the facility, the new location of this facility, the land acquisition, the status of construction, the size of the building, the types of operations that will work at this facility, and other relevant information are set forth at 5 TR 1813-1820. As shown in Exhibit A-82 (QAG-3), the Company is projecting to invest $3,405,000 in the Lansing Service Center in the bridge period and $13,967,000 in the test year.

The Attorney General expressed concern with the project's expenditures. Specifically, Attorney General witness Deupree spoke generally about the delays the Company experienced for the construction of the Lansing Service Center. Mr. Deupree then concluded that there is "uncertainty surrounding the timing and amount of capital expenditures forecasted for a project that has already experienced significant delays and is still in its design phase." 5 TR 3123. As a result, Mr. Deupree said that the "projected costs are not known and measurable" and "will not be used and useful within the projected TY." 5 TR 2926. As a result, he recommended a complete disallowance of all proposed capital expenditures for this project for the bridge period and test year in the total amount of $17.4 million. 5 TR 2926.

The Attorney General's proposed reduction should be rejected as arbitrary. Company witness Quentin A. Guinn explained that Mr. Deupree is incorrect in his assessment of this project and that his proposed disallowance should be rejected. While Mr. Guinn acknowledged that material shortages, supply chain disruptions, and related pandemic period disruptions beyond the

Company's control slowed the progress of these projects since the conclusion of Case No. U-20963, he explained that the Company has, nevertheless, continued executing its project plans. 5 TR 1841. Land acquisition and rezoning of the land parcel is complete. 5 TR 1819. Additionally, design engineering and bidding are complete, and a contract has been awarded for a municipal water main extension to the project site. The materials for this extension have been ordered. 5 TR 1820. A design-build contract for construction management services has been competitively bid and awarded, and the architectural design of the building is nearing completion. 5 TR 1820. The Company has also placed orders for modular building parts and materials that will be used to construct the project in 2025. 5 TR 1842.

The pace of the Lansing Service Center Project has increased, and will continue to increase, as the project moves into the construction phase. Mr. Deupree's recommended expenditure adjustment should be rejected, and the Commission should approve the Company's reasonable expenditure amount.

b. <u>Kalamazoo Service Center</u>

References in the Record: Guinn, 5 TR 1825-1829, 1843-1844; Exhibit A-82 (QAG-3), Exhibit A-83 (QAG-4); Deupree, 5 TR 2928-2929

Like the Lansing Service Center Project, the Kalamazoo Service Center Project is a multi-year project and the specifics regarding the reasons for renovating the facility, the types of operations that will work at this facility, and other relevant information are set forth at 5 TR 1825-1829. While the Company had originally planned to replace the Kalamazoo Service Center, the Company now intends to renovate it instead. 5 TR 1826; see also Exhibit A-83 (QAG-4). Staff supported the Kalamazoo Service Center capital expenditures, without adjustment. As shown in Exhibit A-82 (QAG-3), the Company is projecting to invest $4,815,000 in the Kalamazoo

Service Center in the bridge period and $9,424,000 in the test year. 5 TR 1827. The Attorney General expressed concern with the project's expenditures.

Attorney General witness Deupree questioned the pace of the Company's spending. Mr. Deupree described the Kalamazoo Service Center Renovation Project as "still in its design phase" and characterized the projects as having "uncertainty surrounding the timing and amount of capital expenditures" associated with the Kalamazoo Service Center Project. 5 TR 2928-2929. As a result, Mr. Deupree recommended a $14.2 million disallowance saying that "the costs are not known and measurable." 5 TR 2929.

Mr. Guinn explained that Attorney General witness Deupree is incorrect in his assessment of this project and his proposed disallowances should be rejected. This is despite the fact that the project is ongoing. The Company has bid and awarded a contract for construction management services, as well as a contract for architectural and engineering design services. 5 TR 1828. Architectural and engineering design work on the project is in progress. Additionally, the Company has relocated employees to perform asbestos remediation work and has begun renovation and construction activities associated with the Kalamazoo Service Center Project. 5 TR 1843. The pace of the Kalamazoo Service Center Project has increased and will continue to increase. Thus, Mr. Deupree recommended expenditure adjustment should be rejected, and the Commission should approve the Company's reasonable expenditure amount.

c. <u>Hastings Service Center</u>

References in the Record: Guinn, 5 TR 1820-1824, 1843, Exhibit A-82 (QAG-3); Deupree, 5 TR 2926-2928

The Company is planning to construct a new Hastings Service Center at the existing service center location to include an adjacent property that the Company is negotiating to purchase from the adjacent landowner. This new facility will house most employees currently working at the

existing service center. 5 TR 1820. Specifics regarding the need for this facility, the new location of this facility, the land acquisition, status of construction, size of the building, the types of operations that will work at this facility, and other relevant information are set forth at 5 TR 1820-1824.

As shown in Exhibit A-82 (QAG-3), the Company is projecting to invest $136,000 in the Hastings Service Center in the bridge period and $0 in the test year. 5 TR 1823. The Company's projected investment in the bridge period is for acquisition of the land parcel which will allow for expansion of the existing Hastings site and construction of the new facility. 5 TR 1824. The Company is also developing conceptual plans and cost estimates for the project. These plans were approved by the Barry County Road Commission (owner of the adjacent parcel). 5 TR 1824.

The Attorney General recommended removal of the costs associated with the initial investment in the Hastings Service Center Project. 5 TR 2928. The Attorney General does not challenge the reasonableness of the Company's project expenditures. Instead, Mr. Deupree argued that these costs should be removed because "the projected costs are not known and measurable and because the project will not be used and useful" in the test year. 5 TR 2927. This fails to recognize that the Company limited its projected capital expenditures to the acquisition of the property requisite to constructing the project. 5 TR 1843. This is underway and the Company and the Barry County Road Commission are in the process of signing a mutually negotiated agreement for the sale and transfer of this property. Thus, the Company requests that the Commission approve the reduced spending amount.

d. Asset Preservation – Unplanned Repairs

References in the Record: Guinn, 5 TR 1809, 1844; Exhibit A-82 (QAG-3); Hansen, 5 TR 3696-5697

Asset Preservation – Unplanned Repairs includes unplanned corrective maintenance and repair of assets. As shown in Exhibit A-82 (QAG-3), the Company is projecting to spend $1,129,000 in the bridge period and $1,653,000 in the test year on emergent repairs. Staff recommended an adjustment to these expenditures in the amount of $106,000 during the projected test year. This adjustment was due to an error in the calculation of the five year average, which was the basis for the Company's projection. 5 TR 3697. The Company agrees with Staff's partial disallowance, and therefore, the Company is amending its forecasted capital expenditures for Asset Preservation – Unplanned Repairs to $1,547,000. 5 TR 1844.

e. Control/Dispatch Center Consolidation

References in the Record: Snider, 5 TR 2538-2540; Guinn, 5 TR 1832-1833, 1844, Exhibit A-82 (QAG-3); Deupree, 5 TR 2929-2930

In Case No. U-21389, the Commission approved the Unified Control Center. By consolidating the current electric dispatch, distribution control, and system control centers into a single primary operating center with a remote backup center, the Company will improve grid operations in blue-sky and catastrophic weather conditions. The Control/Dispatch Center Consolidation is the same project as the Unified Control Center. As explained by Company witness Andrew R. Snider; the benefits, scope, total cost, and schedule of the consolidation project are the same as what was approved in Case No. U-21389. 5 TR 2538. A summary of the project and its benefits are at 5 TR 2539-3540.

Company witness Quinn provided the status of this renovation project. As shown in Exhibit A-82 (QAG-3), the Company is projecting to invest $4,903,000 in the Control/Dispatch Center Consolidation renovations in the bridge period and $5,570,000 in the test year. 5 TR 1833.

The conceptual plans and cost estimates have been developed, and design and engineering are being performed. *Id*. The Attorney General contested recovery of $10.5 million in expenditures indicating that they are "not known and measurable", and the project will not be "used and useful" in the test year. 5 TR 2930. This ignores the fact that the requested funding is for the continuation of an ongoing project that is targeted for completion in mid-2026. This project is on track and the project's pace is entirely consistent with the project timelines represented in the previous electric proceeding. Accordingly, the Company requests that these reasonable costs be approved by the Commission.

5. Fleet Services Capital Expenditures

References in the Record: Ballinger, 5 TR 1128, Exhibit A-12 (CEB-1), Schedule B-5.1

Fleet Services provides vehicles and equipment that allow Electric Operations to serve customers with safe, reliable, and affordable service. Fleet Services expenditures are used to preventatively maintain existing vehicles, regularly inspect them, manage the parts inventory, and schedule maintenance across 36 garages by approximately 110 mechanics. 5 TR 1128. The expenditures are also used to acquire and dispose of Company-owned and rented vehicles and related equipment. This includes managing the Fleet capital purchase plan, vehicle specification design, licenses, titles, registration, and ultimately retirement. 5 TR 1128.

Company witness Corey E. Ballinger supported the Company's projected Fleet Services capital expenditures. 5 TR 1125-1175; Exhibit A-12 (CEB-1), Schedule B-5.1. The Company incurred total Fleet Services capital expenditures of $17.687 million in the historical year (the 12 months that ended on December 31, 2023), and projects total electric Fleet Services capital expenditures of $20.425 million for the 12 months ending December 31, 2024; $2.825 million for the two months ending February 28, 2025; and $21.778 million for the projected test year ending February 28, 2026. See Exhibit A-12 (ASC-1), Schedule B-5.1, line 6, columns (b)

through (f). Besides capital expenditures for fleet vehicles, tools, and other equipment, there are other costs related to the Company's fleet that are treated as "fleet responsibility" dollars. See Exhibit A-37 (ASC-2). Fleet responsibility dollars are allocated to fleet units based on their defined work assignments. 5 TR 1131. Fleet responsibility costs are allocated to both capital and O&M expenses. No party contested the Company's Fleet Services expenditures. The Commission should, therefore, approve the Company's proposed expenditures.

6. Information Technology Capital Expenditures

a. IT Overview and Expenditures

References in the Record: Kandan, 5 TR 1847, 1854-1856, 1871-1942, Exhibits A-84 (SK-1), A-12 (SK-5), Schedule B-5.5, A-88 (SK-6), and A-89 (SK-7)

Company witness Shivaji Kandan described the Company's proposed capital expenditures for the Information Technology ("IT") Department. Mr. Kandan is the IT Director for the Operational Technology Department. 5 TR 1847. His job is to see that the Company's electric and gas business operations have access to reliable, stable, and safe technology infrastructure and applications. 5 TR 1847. The biggest challenge for the IT Department is to successfully integrate emerging technologies, data, and analytics with existing systems to support the Company's objectives, including the systems that enable the Company to quickly restore customers' power when it is interrupted. Storm restoration relies heavily on accurate data and high-performing systems that can handle large amounts of data. The Company's customers depend on these systems to report outages, receive timely information on estimated restoration times, and view the outage map to see impacted areas.

Technology is integral to the Company's electric generation and distribution strategy, as well as its ability to engage with customers in a meaningful way and to secure its resources from cybersecurity threats. On the generation side of the business, the Company has led and is leading

a clean energy transformation by exiting coal-fired generation and increasing the amount of renewable energy – like solar, wind, and battery storage – in its generation portfolio. With this move toward more distributed and complex generation, the Company needs to invest in new technology. 5 TR 1854.

On the distribution side of the business, the Company's Reliability Roadmap lays out the Company's plans to invest in a modern distribution system to safely deliver affordable and reliable power to customers throughout Michigan with a goal of fewer and shorter power outages. Mr. Kandan explained how the Company's plan for a reliable and resilient modern electric grid requires technologies to support advanced capabilities like Volt-VAR Optimization and CVR that reduce system energy losses and peak demand. Technology further supports FLISR to automatically identify where faults are on the system and reroute power to unaffected areas, while also allowing the Company to efficiently manage load given the increasing number of DERs near that load. 5 TR 1854-1855.

Concerning customer service and cybersecurity, technology empowers the Company to organize and analyze customer data and ultimately to better understand, communicate, and engage with customers in a meaningful way. Technology is also needed to connect with customers using their chosen communication channel; to provide accurate, timely energy bills and consistent payment processes; and to offer customers options to monitor and understand their energy consumption. 5 TR 1855. This must all be accomplished while keeping the Company and customers safe from cyberattacks. Cybersecurity threats are increasing daily in numbers, impact, and sophistication. Today, these threats are one of the greatest security risks an organization faces. The IT Department must keep pace with these threats by retrofitting existing infrastructure and applications to secure customer and Company data and assets. 5 TR 1855-1856.

In 2023, the Company allocated $39,047,000 in capital expenditures to the IT Department for work completed to support the electric business. 5 TR 1871; Exhibit A-12 (SK-5), Schedule B-5.5. For the 14-month bridge period ending February 28, 2025, the Company projects it will invest $51,592,000 in IT capital expenditures, while for the test year, it projects it will invest $38,908,000. 5 TR 1872. Mr. Kandan described, in detail, the Company's capital programs and the projects within each program in his testimony and exhibits. See 5 TR 1871-1942; Exhibit A-12 (SK-5), Schedule B-5.5; Exhibit A-88 (SK-6); and Exhibit A-89 (SK-7).

The Company's proposed IT capital expenditures are needed, well supported in testimony, and should be approved. Staff's proposed disallowances to the Company's projected capital expenditures, which are discussed below, should be rejected.

b. Proposed Capital Expenditure Reductions

References in the Record: Kandan, 5 TR 1948-1949; Hansen, 5 TR 3695-3696, Exhibit S-10.1

Staff witness Hunter Hansen recommended that the Commission reduce the Company's capital expenditures for several IT capital projects – listed below and in Staff Exhibit S-10.1 – by 20% for each project. 5 TR 3695; Exhibit S-10.1. Mr. Hansen's proposed disallowances would reduce the Company's capital expenditures by $2,836,889 for the 14-month projected bridge period ending February 28, 2025 and $338,242 in the projected test year:

- SAP HANA Database Migration;
- IT Operations Management - Service Operations;
- Operational Technology - Service Management Upgrade;
- Software Asset - Service Management Upgrade;
- SolarWinds Performance Monitoring Expansion Upgrade;
- Business Continuity - Program Management Tool;

- Enterprise Risk Management;
- Product Family Enhancements – Application Platforms Services - Capital; and
- Product Family Enhancements – Infrastructure Platforms Services – Capital.

Through an audit question, Staff asked the Company to provide the basis for its cost estimates for these projects, and the Company responded, among other things, that some project costs were estimated based on the costs of past projects of similar size and scope. 5 TR 3695; Exhibit S-10.2. Mr. Hansen said that "no detail [was] provided on those projects" and that Staff lacked information about the projects' capital software, labor, and contractor cost estimates. 5 TR 3695-3696. The Company provided what was requested. If Staff had asked for more information, the Company would have willingly provided more. In many instances, the information provided was based on actual amounts spent on the same projects. It is not clear that Staff realized this. Regardless, the forecasts for these projects are more reliable than Staff gives them credit for.

As further background, the Company reduced the Company's projections by 20% for all IT projects that were based on Rough Order of Magnitude ("ROM") estimates. This is consistent with past cases where the Commission has reduced utility projected costs by 20% to reflect the lower bound of projects' estimated cost range when those costs were based on ROM estimates that the Commission found too imprecise for ratemaking purposes. See, e.g., MPSC Case No. U-20697, December 17, 2020 Order, pages 135-138. In this case, the Company identified projects with ROM estimates in Exhibit A-88 (SK-6), column (j), and reduced these projects' costs by 20% in keeping with past orders. The Company's projections for its other IT projects were not based on ROM estimates and should not receive an ROM adjustment.

Almost all the projects that Staff reduced by 20% in Exhibit S-10.1 were not identified as projects with an ROM estimate since "they were at a more advanced stage of planning." Kandan,

5 TR 1948-1949. Indeed, many of the projects were in the middle of being executed, so the Company's projected capital expenditures were based on the best information possible – actual project experience. These projects should not be subject to an ROM reduction. Further, Staff reduced by 20% the Company's total projected capital expenditures for each project rather than isolating the amount allocated to the electric business and the amount being requested in this case. In the sections that follow, the Company describes each project, explains why no disallowance is warranted, and calculates what the disallowance would be for the electric business alone.

Staff witness Brittney Klocke's recommendation that the Commission reject all the Company's proposed capital expenditures for its Click to Chat and Commercial and Industrial Online Account Management projects are also addressed below.

i. SAP HANA Database Migration

References in the Record: Kandan, 5 TR 1936-1938, 1949-1951, Exhibit A-243 (SK-12); Hansen, 5 TR 3695-3696, Exhibits S-10.1 and S-10.2

The High-performance ANalytic Appliance ("HANA") is the Company's Systems, Applications, and Products' ("SAPs") database technology (a record-keeping system) with in-memory computing. 5 TR 1936-1938, 1949. In 2027, SAP will stop supporting versions of SAP that are not running on SAP's new platform, called SAP Business Suite 4 HANA or S/4HANA. The SAP HANA Database Migration project positions the Company to move to S/4HANA by migrating its existing SAP databases from Oracle to SAP HANA before the required move to S/4HANA. 5 TR 1949. For the SAP HANA project, Staff witness Hansen proposed to reduce the Company's capital expenditures by $1,380,724 in the projected bridge period ending February 28, 2025. 5 TR 1949; Exhibit S-10.1; Exhibit A-243 (SK-12). Staff was wrong to recommend this reduction for two reasons.

First, the SAP HANA Database Migration project was underway when the Company estimated its costs and work already completed was the basis for its estimated costs. The Company told Staff that the 2024 and 2025 estimated costs for the SAP HANA project were based on work completed in 2023 to move the same project's non-production environments to the cloud. Exhibit S-10.2; 5 TR 1950. But it is not clear that Staff realized this. It classified the SAP HANA project as Class III project under the Association for the AACE cost estimate classification system because its cost estimates were allegedly "based on the costs of past projects of similar size and scope." 5 TR 3695. In fact, the SAP HANA project was based on costs from the same project. 5 TR 1950. The Company's cost estimate for the project are accurate, detailed, and definitive.

Second, Staff did not request all the information it needed to evaluate the SAP HANA Database Migration project. 5 TR 1950. Staff admitted that it did not have "capital software, labor, or contractor costs" and did not say it specifically asked for this information – only that it asked generally for the basis of the Company's cost estimates. 5 TR 3695-3696. Without this information, Staff arbitrarily classified the SAP HANA project as a Class III AACE project and concluded that the Company's estimate could be as much as 20% too high. 5 TR 1950. With the information now on the record – between the Company's direct and rebuttal testimony and exhibits – there is no reason for Staff to dispute, or the Commission to reject, the Company's projections.

Although unmerited, if Staff's proposed disallowance is adopted, the amount should at least be adjusted. As Mr. Kandan testified, "The projected electric allocation capital expenditures for this project are $1,281,157 for 2024 and $195,762 for two months ending February 28, 2025," and if the Commission adopts Staff's proposed disallowance against the weight of the evidence, "the electric projected capital expenditure disallowance of $256,231 (20% of $1,281,157) for 2024

and $39,152 (20% of $195,762) for two months ending February 28, 2025 would be the correct disallowance amount." 5 TR 1950-1951.

For these reasons, Staff's proposed adjustments to the SAP HANA Database Migration project's capital costs should be rejected or, at a minimum, reduced.

ii. IT Operations Management – Service Operations

References in the Record: Kandan, 5 TR 1942 and 1951-1952, Hansen, 5 TR 3695-3696**,** Exhibit S-10.1

The IT Operations Management - Service Operations – project is for a service mapping tool that leverages infrastructure data to identify all the Company's assets that support a service, with information about the service-specific relationship. 5 TR 1951. According to Mr. Kandan, this project "will reduce the time for resources to identify and troubleshoot critical [IT] incidents by 30%, which will result in avoided labor costs." 5 TR 1942. Staff nonetheless proposed reducing the Company's projected capital expenditures for this project by $618,396 (20% of $3,091,979) in 2024 for the same reasons it proposed reducing the Company's projections for the SAP HANA Database Migration project. 5 TR 1951, 3695-3696; Exhibit S-10.1. Staff is wrong for the same two reasons. See discussion *supra* at Section III.A.6.b.i (discussing the SAP HANA Database Migration project); 5 TR 1951-1952 (Company witness Kandan's testimony specifically refuting Staff's proposed disallowance for the IT Operations Management - Service Operations – project).

Although unmerited, if Staff's proposed disallowance is adopted, the amount should at least be adjusted. As Mr. Kandan testified, "The projected electric allocation capital expenditures for this project are $194,939 for 2024," and if the Commission adopts Staff's proposed disallowance against the weight of the evidence, "the electric projected capital expenditure disallowance of $38,988 (20% of $194,939) for 2024 would be the correct disallowance amount." 5 TR 1952.

For these reasons, Staff's proposed adjustments to the IT Operations Management - Service Operations – project's capital costs should be rejected or, at a minimum, reduced.

iii. Operational Technology – Service Management Upgrade

References in the Record: Kandan, 5 TR 1952-1953, Exhibit A-89 (SK-7); Hansen, 5 TR 3695-3696, Exhibit S-10.1

The Operational Technology – Service Management Upgrade – project consolidates Operational Technology assets into a single database, automates asset tracking and asset maintenance, and creates a Company-wide governance structure with documented standards and processes to manage the assets. Kandan, 5 TR 1952; Exhibit A-89 (SK-7), page 91. This project brings many benefits. "Overall, having data in one system simplifies operations, enhances efficiency, and empowers the company to make better informed decisions." Exhibit A-89 (SK-7), page 91. Despite these benefits, Staff proposed reducing the Company's projected capital expenditures for this project by $193,075 (20% of $ 965,375) in 2024 for the same reasons it proposed reducing the Company's projections for the SAP HANA Database Migration project. 5 TR 1953, 3695-3696; Exhibit S-10.1. Staff is wrong for the same two reasons. See discussion *supra* at Section III.A.6.b.i (discussing the SAP HANA Database Migration project); 5 TR 1953 (Company witness Kandan's testimony specifically refuting Staff's proposed disallowance for the Operational Technology – Service Management Upgrade – project).

Although unmerited, if Staff's proposed disallowance is adopted, the amount should at least be adjusted. As Mr. Kandan testified, "The projected electric allocation capital expenditures for this project are $164,952 for 2024," and if the Commission adopts Staff's proposed disallowance against the weight of the evidence, "the electric projected capital expenditure disallowance of $32,990 (20% of $164,952) for 2024 would be the correct disallowance amount." 5 TR 1954.

For these reasons, Staff's proposed adjustments to the Operational Technology – Service Management Upgrade – project's capital costs should be rejected or, at a minimum, reduced.

iv. Software Asset – Service Management Upgrade

References in the Record: Kandan, 5 TR 1954-1955, Exhibit A-89 (SK-7)

The Software Asset – Service Management Upgrade – project will allow the Company to streamline and optimize how it manages and monitors its software assets and will help ensure it is complying with software licensing agreements. 5 TR 1954; Exhibit A-89 (SK-7), page 117. Staff nonetheless proposed reducing the Company's projected capital expenditures for this project by $233,937 (20% of $1,169,683) in 2024 for the same reasons it proposed reducing the Company's projections for the SAP HANA Database Migration project. 5 TR 1954-1955, 3695-3696; Exhibit S-10.1. Staff is wrong for the same two reasons. See discussion *supra* at Section III.A.6.b.i (discussing the SAP HANA Database Migration project); 5 TR 1954-1955 (Company witness Kandan's testimony specifically refuting Staff's proposed disallowance for the Software Asset – Service Management Upgrade – project).

Although unmerited, if Staff's proposed disallowance is adopted, the amount should at least be adjusted. As Mr. Kandan testified, "The projected electric allocation capital expenditures for this project are $83,277 for 2024," and if the Commission adopts Staff's proposed disallowance against the weight of the evidence, "the electric projected capital expenditure disallowance of $16,655 (20% of $83,277) for 2024, would be the correct disallowance amount." 5 TR 1955.

For these reasons, Staff's proposed adjustments to the Software Asset – Service Management Upgrade – project's capital costs should be rejected or, at a minimum, reduced.

v. SolarWinds Performance Monitoring Expansion Upgrade

References in the Record: Kandan, 5 TR 1956-1957; Hansen, 5 TR 3695-3696, Exhibit S-10.1

Through the SolarWinds Performance Monitoring Expansion Upgrade project, the Company will be able to better monitor how its IT applications and infrastructure are performing by consolidating information the Company needs to monitor these systems into a single screen with dashboards for critical systems. 5 TR 1956; Exhibit A-89 (SK-7), page 119. This will allow the Company to minimize unplanned service interruptions, extended service interruptions, and system degradation. 5 TR 1956. Despite these benefits, Staff proposed reducing the Company's projected capital expenditures for this project by $352,829 (20% of $1,764,146) in 2024 for the same reasons it proposed reducing the Company's projections for the SAP HANA Database Migration project. 5 TR 1956-1957, 3695-3696; Exhibit S-10.1. And Staff is wrong for the same two reasons. See discussion *supra* at Section III.A.6.b.i (discussing the SAP HANA Database Migration project); 5 TR 1956-1957 (Company witness Kandan's testimony specifically refuting Staff's proposed disallowance for the SolarWinds Performance Monitoring Expansion Upgrade project).

Although unmerited, if Staff's proposed disallowance is adopted, the amount should at least be adjusted. As Mr. Kandan testified, "The projected electric allocation capital expenditures for this project are $1,029 for 2024," and if the Commission adopts Staff's proposed disallowance against the weight of the evidence, "the electric projected capital expenditure disallowance of $206 (20% of 1,029) for 2024 would be the correct disallowance amount." 5 TR 1957.

For these reasons, Staff's proposed adjustments to the SolarWinds Performance Monitoring Expansion Upgrade project's capital costs should be rejected or, at a minimum, reduced.

vi. Product Family Enhancements Projects

References in the Record: Kandan, 5 TR 1950, 1961-1963, and 1968, Exhibits A-89 (SK-7) and A-92 (SK-10); Hansen, 5 TR 3695-3696, Exhibit S-10.1

The Product Family Enhancements projects will allow the Company to quickly complete small but important enhancements to existing software for new or improved functionality in response to changing business and customer needs. 5 TR 1961; Exhibit A-89 (SK-7), page 93. The Company must be agile in the current digital environment, and this funding will allow the Company to react in real time to changing business conditions, compliance requirements, and customer feedback. Exhibit A-89 (SK-7), page 93. Despite these benefits, Staff proposed reducing the Company's projected capital expenditures for these projects by 20% as follows (Staff's proposed O&M reductions for these projects are addressed later in this brief):

- Product Family Enhancements – Application Platforms Services Capital – project: A $36,657 (20% of $183,285) reduction for the 2 months ending February 28, 2025 and a $210,614 (20% of $1,053,068) reduction for the projected test year. 5 TR 1962.

- Product Family Enhancements – Infrastructure Platforms Services - Capital – project: A $21,271 (2 months of $106,357) reduction for the 2 months ending February 28, 2025 and a $127,628 (20% of $638,142) reduction for the projected test year.

Staff proposed the disallowance for these two programs for the same reasons it proposed reducing the Company's projections for the SAP HANA Database Migration project. 5 TR 1962-1963, 3695-3696; Exhibit S-10.1. Staff is wrong for similar reasons.

First, the Company forecasted the capital costs for these Product Family Enhancements projects based on actual three-year historical average spending on the former Enhancements-IT-Capital and Product Family Enhancements-IT/Digital Foundation-Capital projects. 5 TR 1962. As their names suggest, these programs are more than just similar to the Product Family Enhancements projects described in this case, they are predecessors to the proposed Product Family Enhancements projects. Further, Company witness Kandan compared historical capital

and O&M projections with actual spending, revealing that the Company's projected costs for its Enhancement projects, which are built into rates, have historically been lower than the amount the Company actually spent on these projects[9]:

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
				Projected Capital					
	Year	Case No.	Source	2019	2020	2021	2022	2023	2024
1	2019 Total Projected	U-20134	A-84 (JRH-3)	2,710,665					
2	2020 Total Projected	U-20697	U20697-SA-CE-022 Response		2,082,418				
3	2021 Total Projected	U-20697	U20697-SA-CE-022 Response			2,742,271			
4	2022 Total Projected	U-20963	A-108 (JDT-7)				3,897,882		
5	2023 Total Projected	U-21224	A-171 (JMW-6)					5,317,424	
6	2024 Total Projected	U-21389	A-180 (HNW-6)						5,460,578
7	2025 Total Projected	U-21585	A-88 (SK-6)						
8	2026 Total Projected	U-21585	A-88 (SK-6)						
				Actual/Projected Capital					
	Project Name	Case No.	Source	2019	2020	2021	2022	2023	2024*
9	2019 Total Actuals	U-20963	A-108 (JDT-7)	3,282,246					
10	2020 Total Actuals	U-20963	A-108 (JDT-7)		3,745,910				
11	2021 Total Actuals	U-21224	A-171 (JMW-6)			5,549,802			
12	2022 Total Actuals	U-21389	A-180 (HNW-6)				7,321,154		
13	2023 Total Actuals	U-21585	A-88 (SK-6)					4,192,843	
14	2024 Total Projected	U-21585	A-88 (SK-6)						7,330,603
15	Projected to Actual Variance			571,581	1,663,492	2,807,531	3,423,272	(1,124,581)	1,870,025

*2024 projected based on 1 month of actuals and 11 months of forecast data

Second, as with the SAP HANA Database Migration project, Staff did not request all the information it needed to evaluate the Product Family Enhancements projects. 5 TR 1962. Staff admitted that it did not have "capital software, labor, or contractor costs" and did not say it specifically asked for this information – only that it asked generally for the basis of the Company's cost estimates. 5 TR 3695-3696. Without this information, Staff arbitrarily classified the Product Family Enhancements projects as a Class III AACE project, concluding that the Company's estimate could be as much as 20% too high. 5 TR 1950. With the information now on the record – between the Company's direct and rebuttal testimony and exhibits – there is no reason for Staff to dispute, or the Commission to reject, the Company's projections.

[9] The image included below is taken from Exhibit A-92 (SK-10) and is the capital portion of the comparison; the O&M portion of the graph is omitted here since O&M costs for the Enhancement projects are discussed later. The years 2025 and 2026 have also been removed in this excerpt for readability.

Although unmerited, if Staff's proposed disallowance to the Product Family Enhancements projects is adopted, the disallowance amounts should at least be adjusted as follows:

- For the Product Family Enhancements – Application Platforms Services Capital – project, Mr. Kandan testified that "[t]he projected electric allocation capital expenditures are $127,658 (2 months of $765,948) for 2 months ending February 28, 2025 and $733,462 (10 months of $765,948 and 2 months of $571,029) for the projected test year . . . ." 5 TR 1963. So, if the Commission adopts Staff's proposed disallowance against the weight of the evidence, "the electric projected disallowance of $172,224 (20% of $861,120) capital expenditures for 2 months ending February 28, 2025 and [the] projected test year . . . would be the correct disallowance amounts." 5 TR 1963.

- For the Product Family Enhancements – Infrastructure Platforms Services - Capital – project, Mr. Kandan testified that "[t]he projected electric allocation capital expenditures are $74,078 (2 months of $444,466) for the two months ending February 28, 2025 and $444,466 (10 months of $444,466 and 2 months of $444,466) for the projected test year . . . ." 5 TR 1967-1968. So, if the Commission adopts Staff's proposed disallowance against the weight of the evidence, "the electric projected disallowance of $103,709 (20% of $518,544) capital expenditures for 2 months ending February 28, 2025 and [the] projected test year . . . would be the correct disallowance amounts." 5 TR 1968.

For these reasons, Staff's proposed adjustments to the Product Family Enhancements projects' capital costs should be rejected or, at a minimum, reduced.

vii. Click to Chat

References in the Record: McLean, 5 TR 2183-2184; Klocke, 5 TR 3725-3728

Through Click to Chat, customers can chat with a customer service representative ("CSR") through a chat feature on the Company's website. Staff witness Klocke proposed to fully remove the capital expenditures requested in this case for the Click to Chat project of $99,626, which consists of $96,721 of expenses in the historical year that ended December 31, 2023 and $2,905 in the bridge year ending in December 31, 2024. 5 TR 3725. Ms. Klocke argued that Click to Chat does not have new features, save costs, or reduce calls. 5 TR 3735-3727. But these were never the application's goals. Its purpose is to give customers another option to use when contacting the

Company for assistance. Click to Chat fulfills this purpose. 5 TR 2183. Nearly all issues customers call about can be handled via chat, including outage reporting and status updates, move-in and move-out requests, and reviewing or updating account information. There is inherent value in offering customers different communication channels. 5 TR 2184.

Given the Click to Chat's inherent value, it has been unopposed in the past. The project was included in Case No. U-21308 (the Company's 2022 gas rate case) and Case No. U-21389 (the Company's 2023 electric rate case), and no parties opposed project costs in those cases. In fact, the historical investment in Click to Chat was included in the revenue requirement approved by the Commission in a prior electric rate case (Case No. U-21389). Staff's recommendation would result in a $96,721 disallowance of historical investment that was already included by the Commission. 5 TR 2184. Accordingly, it would be inappropriate to remove the expenditures in this case and the expenditure amount for Click to Chat should be approved.

viii. C&I Online Account Management

References in the Record: McLean, 5 TR 2151-2152, 2185; Klocke, 5 TR 3728

Consumers Energy's customer service portfolio is not an easy process for the Company's large C&I customers. These customers require several individuals to have easy access to their utility accounts. Under the current process, this requires tracking and utilizing multiple logins to the Company's self-service portal and payment of several individual bills. The Company's C&I Account Management Project will support large customers' ability to easily manage multiple accounts via a single login and pay a single bill. 5 TR 2151-2152.

Staff witness Klocke recommended a disallowance ($453,536 capital and $94,058 in O&M) of the Company's costs associated with the C&I Online Account Management tool. 5 TR 3728. While the Company does not agree with the reasoning for Staff's disallowance, it agrees to

withdraw its request for funding for the C&I Online Account Management tool at this time and will further develop its business case related to the project. 5 TR 2185. However, Staff's proposed adjustment failed to acknowledge that the Company already included a 20% ROM adjustment to the expenditure amount for the program. 5 TR 1972. Thus, the Company is agreeing to remove the ROM-adjusted amount of $362,829 ($453,536 less 20% ROM Adjustment) for the project.

7. Security Capital Expenditures

References in the Record: Reed, 5 TR 2417-2427, 2437-2450, Exhibits A-12 (ESR-1) and A-154 (ESR-2)

The Security Department exists to deter threats prior to impacting the Company, detect when malicious activity does occur, recover quickly with minimal effect if or when a threat is successful in causing impact, comply with all governmental and industry regulations, and support delivery on Company goals. 5 TR 2420. The Security Department is made up of Compliance; Physical Security; Engineering; Governance, Risk, Compliance; and the Fusion Center. *Id*. The Compliance team ensures security related rules and regulations are followed. The Physical Security team provides physical security services, including perimeter protection, security guards, card access, cameras, executive protection, investigative services, and the Emergency Management function. The Engineering team designs and deploys new security technology, ensures Company projects meet security standards, and conducts assessments to find relevant system vulnerabilities. The Governance, Risk, Compliance team provides Company security awareness on both physical and cyber security topics; quality assurance; project, program, and financial management; and risk management and privacy program services. *Id*. The Fusion Center team is a 24/7 combined cyber and physical operations center responsible for all security monitoring, operational support, identity and access management, event detection, and incident response. 5 TR 2420-2421.

Managing security risks and combatting associated threats require a robust, dedicated security program focusing on people, process, and technology. 5 TR 2421. Security cannot be thought of as simply an operational (physical) or technology (cyber) issue, but a risk requiring specialization and focus. *Id*.

Company witness Erik S. Reed, Director of Security Governance, Risk, Compliance, presented the Company's projected capital expenditures related to Consumers Energy's security program for the bridge period and the test year in this case. 5 TR 2437-2450. As shown on Exhibit A-12 (ESR-1), Schedule B-5.9, the Company projects capital expenditures for its security program of $8.041 million for the bridge period and $9.143 million for the test year. These expenditures are reasonable and should be approved by the Commission.

8. Demand Response Capital Expenditures

References in the Record: McLean, 5 TR 2162, 2191; Towslee, 5 TR 3718; Exhibit S-12.1

Company witness Steven Q. McLean testified in support of the capital expenditures related to the Company's DR programs. 5 TR 2162. These programs are meant 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. Consumers Energy projects the capital costs for its DR programs to be $.9 million for the projected test year. 5 TR 2163; Exhibit A-12 (SQM-1), Schedule B-5.7. The historical year capital costs were $8,014,000. Exhibit A-12 (SQM-1), Schedule B-5.7.

Staff recommended a disallowance in the amount of $2,012,420 to the Company's historical DR related capital expenditures. 5 TR 3718. This is related to the Commission's Order in Case No. U-21410. The Company agreed with this adjustment in rebuttal testimony as the instant case was filed prior to the conclusion of its 2022 DR reconciliation. 5 TR 2191.

a. Business Demand Response

References in the Record: McLean, 5 TR 2172-2176; Exhibit A-12 (SQM-1), Schedule B-5.7

The Company projects capital costs for the business DR program to be $183,000 during the test year. Exhibit A-12 (SQM-1), Schedule B-5.7, line 2. In the business DR program, the Company works with individual business customers to set up a demand reduction plan at their facility to implement when a DR event is called at a time when electricity demand and costs tend to be highest. Business customers contract for specified load reductions. When MISO expects the grid to be strained because of high electric demand or during high market costs, the Company notifies business DR program participants informing them of when they need to reduce load. 5 TR 2173.

Participants in the business DR program receive compensation for capacity and energy reductions during events based on their capacity reduction during the program enrollment period. 5 TR 2173. The capacity payment is tied to the participant's kW of reduction nominated, and the energy payment is based on kWh reduction during these events. 5 TR 2174. 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 at the end of the program year. *Id*. Actual results vary based on the customer's performance. Non-participating customers benefit from the Company offering a business DR program. The Company's business DR program provides a flexible, repeatable, and scalable capacity resource, and thus all customers benefit by reducing the Company's need to purchase additional capacity during times of peak demand, which reduces the cost of providing power to all customers. 5 TR 2174.

The Company is proposing a change to the Business DR Tariff Program. Under the "reduce to" options for rates GPTU and GI, the Company is adding a cap to the amount of interruptible

load based on historical usage. 5 TR 2175. This change will assure accuracy and equity for customers participating in interruptible service.

The Company is also modifying existing elements of the Business DR Contractual Program. First, the Company is exploring modifying the Business DR Contractual Program to seasons. 5 TR 2175. This will allow for options to enroll in one or multiple seasons or years. *Id*. The Company is also examining the use of different payment structures which are more performance and event based by season. This flexibility will allow the Company to provide beneficial program upgrades and options for customers in a timely fashion, as well as adapt to changing customer and market needs. *Id*. The Company is also working with third-party aggregators to determine future opportunities.

The Company has also sunset the Smart Thermostat Program for small to medium business customers. This program did not achieve the forecasted targets, and the levelized cost in the future were higher than MISO Cost of New Entry ("CONE"). Thus, the Company elected to close the program. 5 TR 2176.

b. <u>Residential Demand Response</u>

References in the Record: McLean, 5 TR 2176 -2180; Exhibit A-12 (SQM-1), Schedule B-5.7

The Company projects capital costs for the Residential DR programs to be $726,000 during the test year. Exhibit A-12 (SQM-1), Schedule B-5.7, line 3. The Company currently offers three Residential DR Programs: a Device Cycling Program, a Dynamic Peak Pricing ("DPP") Program, and a Smart Thermostat Program. 5 TR 2176. The Company is proposing to align the DR event season for these programs with the new MISO seasonal construct from June 1 through August 31. *Id*.

The Smart Thermostat Program is for customers who have central air conditioning and a Wi-Fi enabled smart thermostat. The program uses cloud-based software deployed through the customer's Wi-Fi thermostat to perform a preemptive energy optimization of the home to achieve greater demand savings. 5 TR 2177-2178. The Smart Thermostat Program Pilot has expanded from 1,939 participating customers in 2019 to almost 52,000 cumulative customers in 2023. The Company continues a rapid enrollment glidepath over the next five years to achieve its filed IRP DR targets, adding an estimated 11,000 new customers in 2024 and around 12,500 in 2025. 5 TR 2178. The Company added two Honeywell thermostat options for customers (Home and Total Connect Comfort) in 2023 and plans to expand enrollment options for Honeywell Devices the Residential Online Store in 2024. 5 TR 2178.

The DPP Program is meant to encourage customers to shift their energy consumption during the hours of a DR event. Currently, the Company offers two pricing options under the program, Critical Peak Pricing ("CPP") and Peak Time Rewards ("PTR"). 5 TR 2178. While the approaches of these programs are different, the pricing is the same. The CPP option charges customers a significantly higher rate during a DR event. In exchange, customers are offered a discount on their rate during weekends, holidays, and all hours of the day except 2 p.m. to 7 p.m. In contrast, the PTR option offers customers a payment for reducing their energy during DR events. The more energy usage participants shift outside the hours of the event, the more customers will save. 5 TR 2178. The PTR Program is a critical component to the Company's overall residential DR portfolio because it provides customers a no-risk option to participate in DR. 5 TR 2179. Because of the popularity of the no-risk DR offering, the Company plans to leverage the willingness of customers to participate in the PTR Program to get them familiar with DR before encouraging them to participate in a different program where demand savings to the customer and

the Company are more predictable and controllable. *Id*. While PTR is not actively in-market, there were multiple initiatives that were used to help promote enrollments into the DPP Program and/or ensure that the customer was on the best program for them. One of these initiatives was the CSR incentive program where CSRs would promote DR programs to customers who contacted the call center. The Company worked with over 1,100 customers to upsell them from PTR to the Smart Thermostat Program during 2023. *Id*. The focus of this program upsell was for PTR customers who had been enrolled in at least one DR event season and have not benefited from receiving bill credits. 5 TR 2180.

In the Device Cycling Program, the Company installs load control switches on the pieces of equipment in and around a customer's home. These include the customer's AC condenser and electric water heater. Demand savings are offered in the summer months for the air conditioner and year-round for the electric water heater. 5 TR 2177. When the Company activates a switch, it will cycle the output of the connected load by between 40% and 75% for an air conditioner, and 100% for water heaters. At the end of an event, each system returns to normal operation. *Id*. Participants in the program receive a set monthly bill credit. *Id*. In addition to modifying the Device Cycling Program credit to align with the updated MISO seasonal construct, the Company is proposing to modify the program to remove electric water heaters from the equipment eligible to enroll. 5 TR 2177. The Company is also proposing to end the expansion of the Air Conditioning Peak Cycling Program. 5 TR 2176. This is because these programs are less cost effective than other options available to residential customers.

c. DR Credits

References in the Record: McLean, 5 TR 2171-2172, 2189; Isakson, 5 TR 3610-3614

In Case No. U-21389, the Commission directed Consumers Energy to "file an updated calculation of its DR credits in its next general rate case that includes the latest estimate of CONE and updated values of expected per-customer load reduction for credits that are administered monthly (e.g., the residential air conditioning recycling program), and to include actuals rather than expected values whenever possible." U-21389 Order, pages 97-98. The Company complied with this direction.

Company witness McLean explained that the Company should not update its credits based on the latest estimate of CONE at the time of filing. For the 2024/2025 planning year, the latest estimate of CONE for MISO Zone 7 is $127,135 per MW-year. 5 TR 2171. This is a 20% increase from the prior year. Due to the CONE estimate, the Company is not proposing new credits for its DR programs. This is because Staff has argued that Consumers Energy's DR portfolio is among the most expensive in the country and increasing the credits because CONE has increased is not prudent at this time. *Id*. By maintaining the same credit level, the Company can be more cost effective with these programs and the overall portfolio.

The Company did review the credit amount for DR programs with monthly credits, as well as the per-customer load reduction. The only active program this would apply to is the Air Conditioning Peak Cycling Program. In 2023, the Company did not have any events in which it could calculate a new value, so the per customer load reduction value remains at 0.60 kW. *Id*. The credit, however, would be modified due to the Company's proposal to align with MISO's summer season and remove September. The new credit would be $9.50 per summer billing month. This is based on the new credit calculation (($127,135 per MW-year / 1,000 * 75% * 0.60 kW reduction

per customer) / 3 summer months = $19.07 per summer billing month) with the application of a 50% reduction for administrative costs. 5 TR 2172. Staff reviewed the proposed credit amount and disagreed with its calculation. 5 TR 3613. Staff witness David W. Isakson recommended that credit be set to $5 per month. This proposal is based on multiplying the proposed summer GI credit ($8.50) times the expected 0.6 kW average customer load reduction, which is rounded to the nearest whole dollar amount (from $5.10 to $5). *Id*. This methodology applies the same price for a demand reduction offered to all other DR customers but converts it to the flat monthly credit to which residential Air Conditioning Peak Cycling Program customers are accustomed. *Id*. The Company agrees with Staff's proposed credit. 5 TR 2189.

For DR programs that rely on the value of CONE for the credit mechanism, the Company reviewed the credit amounts based on the updated CONE value. This impacts the General Interruptible Provision. Based on the credit calculation and maintaining the $1 differential between summer and non-summer months, the credit would be $8.50 per kW-month in the summer and $7.50 per kW-month in the non-summer. 5 TR 2172. Staff agrees with the proposed credit amount. 5 TR 3613.

Accordingly, the Company and Staff request the Commission set the Air Conditioning Peak Cycling Program credit to $5 for the summer months when the program is active and set the summer credit for the General Interruptible Provision to $8.50 per kW for the summer and $7.50 per kW for the winter.

9. <u>Customer Experience Capital Expenditures</u>

References in the Record: McLean, 5 TR 2139; Exhibit A-12 (SQM-1), Schedule B-5.7

Consumers Energy witness McLean projected the Company's capital expenditures related to the direct work in the Customer Experience and Operations ("CX&O") organization. The Company does not project any test year capital expenditures for this organization. Exhibit A-12

(SQM-1), Schedule B-5.7. Support for the CX&O programs and projects is more fully discussed below in the Customer Experience O&M Expense section of this Initial Brief, along with the recommendations made by the parties.

10. Corporate Services Capital Expenditures

References in the Record: Foster, 5 TR 1721-1723, 1730; Exhibit A-12 (MJF-6), Schedule B-5.3

Company witness Matthew J. Foster, Principal Rate Analyst, presented the Company's projected capital expenditures related to Corporate Services. 5 TR 1730. Corporate Services includes the common administrative functions of a regulated corporation, which include Sustainability and External Affairs; Legal, Ethics, and Risk Management; People and Culture, and Learning and Development; Finance and Corporate Safety; Strategy; General Activities; and Administrative or Other costs. 5 TR 1721-1723. The Company projects Corporate Services capital expenditures in the amount of $754,000 in the bridge period and $297,000 in the test year, which includes the costs to equip and support the Corporate Services areas with office furniture and equipment, primarily at Company headquarter locations. 5 TR 1730, Exhibit A-12 (MJF-6), Schedule B-5.3.

11. Transportation Electrification Program Capital Expenditures

References in the Record: Myrom, 5 TR 2402-2403, 2406-2407, 2411-2412, 2414; McPhail, 5 TR 2226-2228, 2277-2278; Lynd, 4 TR 722

Company witness Jeffrey A. Myrom, Director of EV Customer Products, proposed enhancements to the Company's EV programs focused on three key strategic programs, all designed to promote off-peak charging, among other things:

- PowerMIDrive Residential – Single-family and multi-family outreach, Time-of-Use ("TOU") rate, and rebate programs for off-peak charging at Level 2 ("L2") customer circuit ratings of 50 amps or less. This also includes enhanced rebates for income

qualified customers, and is focused on providing equitable charging opportunities at apartments, condos, and townhomes.

- PowerMIDrive Public – Destination and community charging outreach, TOU rate, and rebate programs for off-peak charging at L2 customer circuit ratings of 50 amps or less, and at some long-duration locations of Level 1 ("L1") customer circuits of 20 amps or less. Strategic locations such as hotels, campgrounds, conference centers, and long-term parking lots, both optimize off-peak charging and power levels needed for service, and reduce pressure on Direct Current Fast Chargers ("DCFCs") that can be more impactful and challenging to develop. Community charging in public parking lots near multi-family dwellings also helps provide equitable charging opportunities by solving a critical need for residents whose multi-dwelling unit ("MDU") does not offer overnight charging.

- PowerMIFleet – Fleet and workplace charging outreach, TOU rate, and rebate programs for businesses, local governments, non-profits, and educational institutions to optimize off-peak charging. Although some fleet charging (e.g. long-duration direct current) is at power levels higher than the typical L2, the off-peak load shapes incentivized mirror those of the other off-peak programs and help avoid more intensive DCFC infrastructure. Workplace charging also creates equitable charging opportunities by solving a critical need for residents whose MDU does not offer overnight charging. Finally, fleets also benefit their entire communities given their high mileage use and corresponding reductions in local pollution. [5 TR 2402.]

Several of the Company's proposed enhancements are also intended to promote off-peak charging in the Company's Transportation Electrification Programs ("TEPs") – collectively, the PowerMIDrive Residential, PowerMIDrive Public Charging, and PowerMIFleet programs. 5 TR 2406-2407.

"EV adoption and factory developments remain on track for an approximate range of 500 thousand EVs (the Company's Integrated Resource Plan projection) to 630 thousand (the McKinsey projection) in 2030." McPhail, 5 TR 2226-2228. Given the expected growth, it will be critical to steer EV owners to off-peak charging through the Company's programs to avoid more

costly on-peak resources to serve the load. New modeling tools will be important as well. Company witnesses Lynd and Mcphail requested funding for a Load Flow Tool Upgrade that will enhance the Company's ability to forecast, model, and simulate DER and EV load. 4 TR 722; 5 TR 2277-2278. Mr. Myrom testified that this tool will help the Company proactively prepare for new and expanded DCFC locations by enabling the Company to better evaluate load growth and refine TEP designs. 5 TR 2403.

Although more work remains to be done and is being done, the Company is not proposing to increase the amount included in rates for TEPs in this case. "No increases to the TEPs budget previously approved are proposed, and no changes are being made to the core program strategies to optimize off-peak charging for the benefit of all customers from these recent permanent program approvals by the MPSC." 5 TR 2405-2406. Other parties to this case largely supported the Company's programs and its efforts to promote off-peak charging. Several parties recommended enhancements, many of which the Company plans to adopt.

Staff witness Allan David Freeman recommended that the Commission approve all the Company's proposed TEP enhancements and noted that the tool being developed in Case No. U-20898 could be used to improve benefit-cost analyses accompanying future requests for pilots. 5 TR 3868, 3870. The Company also sees value in a benefit-cost framework that will streamline TEP reporting and help Staff, intervenors, and the public evaluate EV programs. 5 TR 2411-2412.

MNSC witness Jester recommended that the Company's proposed TEP enhancements be approved, that societal benefits and costs be considered in future TEP proceedings, that the Company thoroughly evaluate EV charging distribution system planning, and that the Company examine unmet needs for public DCFC charging in the next TEP report. 5 TR 3119-3120. The

Company agrees that societal benefits should be considered in future TEP reports and that additional EV load analyses will aid future planning. 5 TR 2411-2412.

As Mr. Myrom paraphrased MEIU witness Sherman's testimony, she recommended "approval of the Company's TEP customer program enhancements, the inclusion of societal benefits in future EV filings, increased rebate values for battery-integrated DCFCs, and the continuation of rebates for DCFCs." 5 TR 2412. MEIU witness Sherman included significant detail regarding the challenges of bringing battery-integrated DCFCs, and DCFCs in general, to market. Considering the information that Dr. Sherman provided, it makes sense to increase certain DCFC rebates. As a result, the Company proposes to increase the battery-integrated DCFC rebate to $50,000 and to continue DCFC rebates at $50,000. If the Commission approves this proposal, it would mean that a host site could earn a total rebate of up to $100,000 per 150 kW DCFC port (i.e. up to $50,000 from each fast-charging rebate category). 5 TR 2414.

12. Accumulated Provision For Depreciation

References in the Record: Exhibit A-12 (JCA-33), Schedule B-3; Exhibit S-2, Schedule B-1; Exhibit A-255 (HJM-4)

The originally filed accumulated provision for depreciation for the projected test year was $6,355,195,000. Exhibit A-12 (JCA-33), Schedule B-3, line 17, column (c). Staff witness Timothy G. Witt provided Staff's projected test year accumulated provision for depreciation in the non-jurisdictional (total Company) amount of $6,340,272,000. 5 TR 3543; 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. 5 TR 3543.

In rebuttal, the Company adjusted the Company's originally filed revenue deficiency based on facts and circumstances revealed after the filing of this case. 4 TR 452. These adjustments

resulted in a total adjusted accumulated provision for depreciation for the projected test year of $6,346,926,000. Exhibit A-255 (HJM-4), line 2, column (2). These amounts are also presented in Appendix B of this Initial Brief. The Commission should approve the depreciation reserve amount of $6,346,926,000.

B. Working Capital

1. Working Capital Methodology And Calculation

References in the Record: Myers, 4 TR 401-402; Exhibit A-12 (JCA-35), Schedule B-4a; Exhibit A-258 (HJM-7)

Rate case working capital is developed using the balance sheet methodology. 4 TR 401. Use of the balance sheet methodology was mandated by the Commission in Case Nos. U-7350 and U-15895. 4 TR 402. The Company requests that working capital be set at a jurisdictional amount of $ 3,180,304,000 for purposes of determining rate base in this case. See Exhibit A-258 (HJM-7); line 19, column (d). The Company's projection is reasonable and consistent with the approach typically used in determining test year working capital using the balance sheet methodology.

The Company, in its initial filing, developed its projected test year working capital requirement using the 13-month average historical December 2023 working capital as its starting point. 4 TR 401. The December 2023 average balances were then adjusted to reflect changes to: i) pension and Other Post-Employment Benefits ("OPEB") balances based on projections sponsored by Company witness Kendra K. Grob, and the regulatory asset and liability related to the: volatility mechanism; (ii) accrued tax balances; (iii) cloud prepayment balances sponsored by Company witness Kandan; (iv) regulatory asset balances for PowerMIDrive and PowerMIFleet deferred costs; (v) regulatory asset balances for Karn and Campbell retention costs, Campbell plant's net book value, and various coal plants' decommissioning and ash disposal costs; (vi) cash balance sponsored by Company witness Marc R. Bleckman; and (vii) the voluntary refund

mechanism balance, which was fully utilized as of December 31, 2023. 4 TR 401. Details of these adjustments are shown in Exhibit A-12 (JCA-35), Schedule B-4a.

2. Attorney General's Proposed Working Capital Adjustments

a. The Commission Should Reject the Attorney General's Proposed Reduction to the Company's Cash Balance

References in the Record: Bleckman, 5 TR 1214-1215, 1266-1270; Coppola, 2833-2836, Exhibit AG-1.29

Mr. Coppola recommends a reduction in the Company's projected test year cash level by $27 million, saying that Company witness Bleckman's recommendation of $45.6 million is unreasonable. 5 TR 2836. This is in error and should be rejected by the Commission.

As Mr. Bleckman explained in his direct and rebuttal testimony, the projected cash balance for the test year in this case should equate to approximately 1% of test year electric revenues, which results in a cash balance of $45.6 million and is reflective of normal levels of cash balance. 5 TR 1215, 1266-1267. In Case No. U-21389, the Commission adopted the ALJ's finding that "the use of 1% of revenues as a benchmark for working capital cash is not arbitrary or inapplicable to determining the reasonableness of the amount of cash on hand." 5 TR 1268. It is also important to remember that the Company has used alternative historical periods to reduce its projected cash balances for the test year when appropriate, for example in Case Nos. U-21148 and U-20963. 5 TR 1267. In those cases, using the historical period that included 2020 would have resulted in a cash balance that was higher than what is normally expected and required for the Company. *Id*. As a result, in those cases the Company used cash balances from an alternative historical period that more appropriately reflected normal, lower levels of cash balances. *Id*. While actual cash balances may be higher or lower, the Company consistently projects normal cash levels which equates to approximately 1% of test year revenues.

Mr. Coppola takes a selective and misleading focus on the Company's actual cash balance versus rate case projections to support a reduction of the cash balance in this case. For example, in Case No. U-21224, the Company's Materials and Supplies account balance was $59 million higher in 2023 versus the projection. Also, the Accounts Payable account balance was $31 million lower in 2023 compared to the projection in Case No. U-21224. Therefore, the Commission should reject Mr. Coppola's focus on the Company's actual cash balance versus rate case projections to support a reduction of the cash balance in this case.

Likewise, despite Mr. Coppola's suggestion, it would not be a sound liquidity strategy for the Company and customers for the Company to maintain a permanent layer of short-term debt to "meet its payment obligations." 5 TR 1269. As explained in Mr. Bleckman's rebuttal testimony, short-term financing markets can be volatile and even unavailable, as was the case during the 2008 credit crisis, again in March 2020 as a result of pandemic-related market fear, and again in March 2023 during the banking industry turmoil. 5 TR 1269. Based on the experience and sound business judgment of the Company's Treasury Department, as well as members of the Financial Planning and Analysis Department, the Company does not pursue a strategy that maintains a permanent balance of short-term debt. 5 TR 1269.

Finally, despite Mr. Coppola's suggestion, the Company's short-term cash investments have no bearing on the projected cash balance for the Company in this case. 5 TR 1270. In sum, in the process of proposing to arbitrarily reduce the Company's cash balance, Mr. Coppola fails to recognize the importance of having adequate liquidity on hand for utility operations. 5 TR 1267. The Commission should reject his proposed adjustment.

b. Accrued Interest

References in the Record: Myers, 4 TR 442; Coppola, 5 TR 2836-2838, Exhibit AG-1.29

Attorney General witness Coppola argued that working capital should be reduced by $7.7 million based on his proposed adjustment to accrued interest calculated as the percentage increase in rate base proposed by the Company. 5 TR 2837-2838. The Commission should reject this recommended reduction for several reasons. First, Mr. Coppola's proposed reduction only considers the projected increase in rate base and fails to project any change in interest rates that may also affect accrued interest. 4 TR 442. Second, Mr. Coppola's proposal fails to consider the impact of his other proposals that would reduce rate base by over $950,000,000 and necessarily change any adjustment to accrued interest. *Id*. And finally, Mr. Coppola's proposal is not consistent with the long-standing methodology of calculating working capital in rate cases by making very few adjustments to an actual 13-month average working capital balance. *Id*. Thus, Mr. Coppola's proposed methodology is flawed, and he has not demonstrated a need to change the long-standing methodology for calculating working capital in this case.

c. Pension/OPEB Volatility Mechanism

References in the Record: Myers, 4 TR 443; Coppola, 5 TR 2838-2839

Attorney General witness Coppola recommended a $6.2 million reduction in working capital to reflect a correction regarding the Pension and OPEB Volatility Mechanism. 5 TR 2838-2839. Consumers Energy agreed with the proposed adjustment. 4 TR 443.

d. Ludington Pumped Storage

References in the Record: Myers, 4 TR 443-448; Coppola 5 TR 2839-2841, Exhibit AG-1.30

Attorney General witness Coppola recommended reducing working capital by $3.4 million to remove the regulatory asset balance related to the Ludington plant. 5 TR 2840. Mr. Coppola

argued that the Commission will eventually determine how much of the costs related to the defective work by Toshiba that Consumers Energy will be allowed to recover. *Id*. Mr. Coppola proposed that once the Commission determines the recoverable amount of costs, a return can be calculated and applied at that time. *Id*. Mr. Coppola's proposed reduction should be rejected.

Consumers Energy and DTE Electric Company ("DTE Electric") (as joint owners of the Ludington Plant) have brought a lawsuit against Toshiba to recover damages associated with Toshiba's defective, non-conforming, and incomplete work in overhauling the Ludington Plant. 4 TR 443. In Case No. U-21310, Consumers Energy and DTE Electric (as co-owners of the Ludington Plant) requested that the Commission authorize the companies to place the costs to correct the defective work in a regulatory asset pending the final outcome of the lawsuit. *Id*. On May 18, 2024, the Commission granted the request and issued an order ("U-21310 Order") approving "cost deferral accounting and a regulatory asset for the costs incurred with restoring allegedly defective work performed by [Toshiba] at the Ludington Pumped Storage Plant." U-21310 Order, page 5. The U-21310 Order authorizes Consumers Energy (and DTE Electric) to "place into the regulatory asset all costs associated with the allegedly defective work performed by [Toshiba] at the Ludington Pumped Storage Plant that have not previously been reviewed by the Commission and approved for incorporation into rates," and to also place any liquidated damages or other damages amounts into the regulatory asset to offset corresponding costs. *Id*.

Pursuant to the Commission's order, the Company is recording the costs to perform corrective work at Ludington in a regulatory asset. 4 TR 444. Mr. Coppola's proposal to reduce working capital by the regulatory asset amount would remove the recovery of financing costs incurred by the Company to perform the necessary corrective work. *Id*. This proposal would have the effect of denying Consumers Energy's financing costs until after the lawsuit is concluded,

which would frustrate the regulatory asset's purpose of allowing the Company to move forward with the corrective work while the litigation is pending. *Id*. The Ludington Plant is a critical generation asset in the state of Michigan, and it is a fundamental part of the development of clean energy in the State. 4 TR 445. Corrective work at the Ludington Plant has already begun and it must continue while the lawsuit is pending, and the corrective work must be financed to ensure timely completion of the work. *Id*.

As part of his reasoning to deny Consumers Energy these needed financing costs, Mr. Coppola stated that "costs pertaining to the power outages" at the Ludington Plant related to Toshiba's defective work has been litigated in Power Supply Cost Recovery ("PSCR") cases, and parties in those proceedings have taken different positions as to whether the Company should "absorb the cost of replacement power" associated with the Ludington Plant outages. 5 TR 2840. However, Consumers Energy has excluded replacement power costs recorded to the regulatory asset from the projected working capital amount. 4 TR 446. The projected working capital adjusts the historical 13-month average balance of the regulatory asset to remove all replacement power costs. *Id*. Thus, Mr. Coppola's concerns about unresolved issues related to replacement power costs do not support his proposed reduction in this case.

Mr. Coppola's proposal is also not consistent with established practice for treatment of regulatory assets. 4 TR 447. Including a regulatory asset in working capital (and earning a return on the asset) is an accepted regulatory practice and is consistent with the treatment of other working capital financed by the Company. *Id*. Regulatory assets are generally included in working capital unless they have a separate recovery mechanism, and none of the costs recorded to the Ludington regulatory asset are being recovered in any other way. *Id*. Even though the Commission will ultimately review the reasonableness and prudence of any costs not ultimately recovered from

Toshiba in litigation prior to inclusion in rates, that does not mean that the Company should be prohibited from recovering financing costs for the ongoing corrective work. *Id*.

The regulatory asset approved by the Commission ensures that the Company can effectively complete the corrective work needed while pursuing the litigation against Toshiba for the benefit of customers. 4 TR 447. It would be unreasonable to deny Consumers Energy the financing costs to support that important work.

C. Total Rate Base

References in the Record: Exhibit A-255 (HJM-4)

Consumers Energy requests the Commission set rates using a jurisdictional total rate base for the projected test year of $15,161,786,000. Appendix B, line 8, column (e); see also Exhibit A-255 (HJM-4). The primary components (in thousands of dollars) are:

Total Utility Plant	$ 18,389,174,000
Less: Accumulated Depreciation	(6,346,926,000)
Less: Retainers & Customer Advances	(60,766,000)
Net Utility Plant	$ 11,981,482,000
Working Capital	3,180,304,000
Total Rate Base	$ 13,758,189

A more detailed calculation of rate base is shown in Appendix B to this Initial Brief. The Commission should approve the total rate base amount as presented in Appendix B to this Initial Brief.

IV. CAPITAL STRUCTURE AND RATE OF RETURN

A. Introduction

1. The Company's Capital Structure and ROE will Support the Shared Goal of Enhancing Electric Service Reliability and Resilience

Because credit rating agencies look to the Company's credit metrics and the supportiveness of the regulatory environment to determine the Company's credit quality, and the Company's

credit quality significantly impacts access to capital and the financing terms, and because investors look to favorable rates of return in their determination of whether or not to invest in the Company (and in Michigan) – which also provides much needed capital for infrastructure and renewable energy projects – the Company's capital structure and ROE are critically important.

As discussed below, the Company's equity ratio and ROE are utilized by credit agencies to determine the Company's financial strength and corresponding credit worthiness – which impacts the Company's access to capital at favorable rates for its infrastructure investment. Thus, the Company's equity ratio and ROE must be strong enough to allow it to maintain its credit and raise required capital at reasonable financing rates. Additionally, to continue to attract equity investors to invest in the Company to further its infrastructure investment, the ROE of the Company must be sufficient to assure those investors that their investment is commensurate with investments of comparable risk. In sum, and as consistent with the U.S. Supreme Court's *Bluefield*[10] decision, the Company's equity ratio and ROE must be set at levels to maintain its credit. To achieve this, the Company proposes a capital structure with an equity ratio of 50.75% and an overall rate of return of 6.17%, and proposes an ROE of 10.25%, to support the credit quality of the Company, support access to capital at reasonable rates, and attract investment in the Company to allow it to make the necessary infrastructure investment to assure reliability and resilience of electric supply service to customers.

Further, the Company establishes below that it is sound public policy for the Commission to grant the Company's requested capital structure and rate of return. The U.S. Supreme Court has established that under the Fourteenth Amendment of the United States Constitution equity investors in a public utility, such as Consumers Energy, are entitled to established rates which are

[10] *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)

"sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the [public utility] service." *Bluefield* at 690.

Throughout their respective filings in this case, various parties have lost sight of the Supreme Court's mandate. The Company is entitled to an ROE commensurate with investments of comparable risk and earnings sufficient to assure financial soundness of the utility for the benefit of its investors and its customers, and further, the Company must be able to earn a return that will allow it to both maintain its credit and raise required capital when needed under reasonable terms. *Id.*, *Fed Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944).

As demonstrated below, and throughout the record in this case, a 10.25% ROE and a 50.75% equity ratio are supportive of adequate credit quality at this time and are commensurate with investments of comparable risk; they assure the financial soundness and allow the Company to earn a return that will in turn allow it to maintain its credit and raise required capital to fund reliable and resilient service for customers.

To summarize the state of the current market as discussed further below, there has been a significant increase in the cost of equity since the Company's last rate proceeding (5 TR 1277); there is a demonstrated and relatively high level of risk surrounding the utility industry at present; and thus Mr. Bleckman has clearly demonstrated that his ROE recommendation is in line with authorized ROE analyses in this proceeding, summarized below, and further commensurate with other utilities' authorized ROEs. Taken in sum, the Company has justified its proposed capital structure and ROE. Therefore, based on the evidence presented in this case, the Commission should adopt the Company's financial requests in their entirety.

2. The Proposed Capital Structure and ROE Presented by Staff, the Attorney General, ABATE, and Other Intervenors Do Not Sufficiently Support the Company's Credit Quality Which Imperils the Company's Ability to Support the Key Objectives of the Reliability Roadmap

The positions of Staff, the Attorney General, and ABATE and other intervenors ("Intervening Parties") do not appropriately heed the warnings of credit agencies, nor the consequent risk placed on investor and consumer interests. As the court noted in *Bluefield*, a proper rate of return not only assures "confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties." *Bluefield*, supra, 262 US at 693. As the Court went on to explain in *Hope*, "[t]he rate-making process … involves balancing of the investor and consumer interests." *Hope*, supra, 320 US at 603.

In particular, the Intervening Parties promote risky financial approaches, including repeated efforts to reduce the Company's equity ratio and ROE. They purport to support consumer interests; however, each fails to recognize that efficient and economical management includes planning for unforeseen economic events, which must be part of the Company's financial planning to allow the Company to avoid harmful financial impacts arising out of such events. Instead, each of these parties ignores the importance of financially sound planning and appear content to push the Company to financial margins that would not protect it or its customers. In an apparent effort to lower customers' rates in the short-term, the Intervening Parties recommend random adjustments to the Company's equity level and reductions in the Company's ROE that push the limits of the Company's credit health. They do so by ignoring, trivializing, or undervaluing the words of the credit agencies and act as though uncertainty is not present, and in acting without proper risk mitigation – prudently set equity ratio and ROE – they seem content to risk the

Company's credit and ability to access markets at reasonable rates. They do not recognize that the negative outcomes risked have cascading effects on the Company's cash flow and ability to manage the business in a manner that allows the Company to access capital at reasonable rates in executing infrastructure projects that support what every customer wants – reliability and resiliency in electric service.

The Commission should reject these parties' risky recommendations and should adopt the Company's proposed capital structure (and ROE) as reasonable and appropriate to absorb unforeseen economic events and impacts, support the Company's credit quality, and support the Company's infrastructure investment to enhance electric service reliability and resiliency for customers.

B. Capital Structure

References in the Record: Bleckman, 5 TR 1178-1276, Exhibits A-14 (MRB-1) through A-14 (MRB-7), A-34 (MRB-8) through A-40 (MRB-14), A-206 (MRB-15) through A-212 (MRB-21); Megginson, 5 TR 3560-3579, Exhibit S-4, Schedules D-1 through D-6; Coppola, 5 TR 2785-2800, Exhibits AG-1.19, AG-1.25, 1.26, 1.28; Walters, 5 TR 3376-3377, 3393-3395

1. Consumers Energy's Capital Structure Should be Adopted by the Commission

Company witness Bleckman presented the Company's proposed capital structure, including the overall rate of return. 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 recommends and requests that the capital structure shown on Exhibit A-210 (MRB-19), be used in this case. 5 TR 1183. This represents the actual capital structure as

of December 31, 2023, adjusted for the projected changes in debt, equity, deferred income taxes, and Investment Tax Credit ("ITC") through the end of the test year ending on February 28, 2026. *Id.* The development of the capital structure on a ratemaking basis is shown in columns (b) through (d). The equity ratio as a percentage of permanent capital is 50.75%. The equity ratio as a percentage of total capital is 42.36%. *Id.*

The Company recommends and requests an overall rate of return of 6.17% on an after-tax basis. 5 TR 1183. This overall rate of return is the result of combining the capital structure and cost rates shown on Exhibit A-210 (MRB-19). The cost of the components and the weighted cost are shown in columns (e) through (i). The overall rate of return that the Company is recommending is the weighted cost of the various components of the capital structure. *Id.* Based on the evidence presented in this case, the Commission should adopt the Company's proposed capital structure, including all of its components, as discussed below.

a. Common Equity Balance

References in the Record: Bleckman, 5 TR 1185, 1188, 1193, Exhibits A-14 (MRB-1), Schedule D-1 and A-14 (MRB-2), Schedule D-1a

Mr. Bleckman started with the actual balances of long-term debt, preferred stock, common equity, short term debt, deferred income taxes, and ITC as of December 31, 2023, as shown in Exhibit A-14 (MRB-2), Schedule D-1a, page 1, column (e). He then made the adjustments shown in column (f) to arrive at the average test year balance ending February 28, 2026, in column (g) that the Company is recommending be used in this case. 5 TR 1185. The common equity adjustment of $1.581 billion consists of two components. *Id.* The first is an adjustment to reflect $288 million in projected retained earnings on a weighted average basis from January 2024 through February 2026. *Id.* The second is an adjustment of $1.293 billion to reflect the projected equity infusions on a weighted average basis from January 2024 through February 2026. *Id.*

The equity ratio is an input into Funds From Operations ("FFO") to Debt ("FFO-to-Debt ratio"), and in the view of credit agencies, a high FFO-to-debt ratio corresponds to a high ability to pay debt, which in turn results in higher credit and lower financing costs. 5 TR 1193. As Mr. Bleckman explained in his direct testimony, despite calculating a peer group equity ratio of 53.32%, an equity ratio of 50.75% balances capital investment plans, credit metrics, customer rate impacts, the guidance of this Commission, and continues to support affordable utility infrastructure financing for the state of Michigan. 5 TR 1188.

The evidence in the case shows industry-wide equity ratios have been trending up and peer group analysis presented by Mr. Bleckman, Mr. Megginson, and ABATE witness Christopher C. Walters show that peer-group equity ratios are higher than the 50.75% that the Company is requesting. 5 TR 1190. Specifically, the Company has demonstrated that its proposed common equity balance is reasonable. Based on the totality of evidence presented in this case, the Commission should adopt the Company's equity balance for the test year ending February 28, 2026, of $11.543 billion and equity ratio of 50.75%. Exhibit A-14 (MRB-1), Schedule D-1, page 1 (See also Exhibit A-14 (MRB-2), Schedule D-1a, pages 1 and 3).

b. <u>Long-Term Debt Balance</u>

References in the Record: Bleckman, Exhibits A-14 (MRB-1), Schedule D-1 and A-14 (MRB-2), Schedule D-1a; Megginson, 5 TR 3570, Exhibit S-4, Schedule D-1

Mr. Bleckman projected an average long-term debt balance for the test year of $11.956 billion. Exhibit A-14 (MRB-1), Schedule D-1; Exhibit A-14 (MRB-2), Schedule D-1a, page 1. Staff agreed with this average long-term debt balance. 5 TR 3570; Exhibit S-4, Schedule D-1. Based on the evidence presented in this case, the Commission should adopt the Company's long-term debt balance.

c. Short-Term Debt Balance

References in the Record: Bleckman, Exhibits A-14 (MRB-1), Schedule D-1, and A-14 (MRB-2), Schedule D-1a; Megginson, 5 TR 3570, Exhibit S-14, Schedule D-1; Coppola, AG-1.17

Mr. Bleckman projected an average short-term debt balance for the test year of $281 million. This balance is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1, line 10, column (b), and on Exhibit A-14 (MRB-2), Schedule D-1a, page 1, line 10. The short-term debt balance recommended by Staff and the Attorney General is the same as recommended by the Company. 5 TR 3570; Exhibit S-4, Schedule D-1; Exhibit AG-1.17. ABATE did not perform an analysis of this element of the Company's proposed capital structure. Based on the evidence presented in this case, the Commission should adopt the Company's short-term debt balance.

d. Deferred FIT Balance

References in the Record: Bleckman, Exhibits A-14 (MRB-1), Schedule D-1 and A-14 (MRB-2), Schedule D-1a; Coppola, Exhibit AG-1.17

Mr. Bleckman proposed a deferred tax balance for the test year of $4.430 billion. Exhibit A-14 (MRB-1), Schedule D-1, line 12, column (b); Exhibit A-14 (MRB-2), Schedule D-1a, line 12, column (b). The Attorney General agreed with this deferred tax balance. Exhibit AG-1.17. ABATE did not perform an analysis of this element of the Company's proposed capital structure. The Commission should adopt the Company's deferred FIT balance.

e. Other Capital Structure Balances

References in the Record: Bleckman, 5 TR 1207, Exhibits A-14 (MRB-2), Schedule D-1a; Megginson, Exhibit S-4, Schedule D-1; Coppola, Exhibit AG-1.17

The Company, Staff, and the Attorney General used balances for preferred stock corresponding to balances in the historical period. Exhibit A-14 (MRB-2), Schedule D-1a, line 4; Exhibit S-4, Schedule D-1, line 4; Exhibit AG-1.17, line 2. For the test year Job Development Investment Tax Credit ("JDITC") balance, Mr. Bleckman testified that the Company estimates the

average balance will be $116 million based on internal projections from the Company's Tax Department, with components for JDITC based upon the allocation of long-term debt, preferred stock, and common equity. 5 TR 1207; Exhibit A-14 (MRB-2), Schedule D-1a, page 1, line 19, column (g). This is the same amount recommended by Staff and the Attorney General. Exhibit S-4, Schedule D-1; Exhibit AG-1.17. ABATE did not perform an analysis of these elements of the Company's proposed capital structure. The Commission should adopt the Company's preferred stock balance and JDITC balance.

2. Response in Opposition to Adjustments made by Staff, the Attorney General, and ABATE, to the Company's Capital Structure

a. Staff's Proposed Adjustment to the Company's Capital Structure is Erroneous and Should Be Rejected by the Commission

i. Staff's One-sided Elimination of the Company's Planned Equity Infusions, Which are Needed to Support the Company's Infrastructure Investment, Understates the Company's Needed Capital Balance and Is Unsupported by Sound Ratemaking and Financial Planning Principles and Should be Rejected by the Commission

References in the Record: Bleckman, 5 TR 1187, 1221-1225, 1259, Exhibits A-14 (MRB-1), Schedule D-1, A-14 (MRB-2), Schedule D-1a, A-206 (MRB-15) and A-224 (MRB-33); Megginson, Exhibit S-4, Schedule D-5

Based, in part, on the Company's planned equity infusions needed to support the Company's capital needs, the Company calculated the average common equity balance for the test year as $12.360 billion resulting in an equity ratio of 50.75%. See, Exhibit A-14 (MRB-1), Schedule D-1; Exhibit A-14 (MRB-2), Schedule D-1a. Equity infusions are cash investments made by CMS Energy Corporation ("CMS Energy") into Consumers Energy, thereby increasing the Company's common equity balance. 5 TR 1187. Equity infusions are determined based on the capital spending and financial needs of the Company. 5 TR 1259. The goals of CMS Energy in making these cash investments include maintaining a strong and healthy utility, capable of

serving the needs of its customers. *Id*. This commitment is reflected in the equity infusions from CMS Energy to Consumers Energy over the last several years and the resulting actual equity ratio. *Id*.

Mr. Megginson suggests an invalid process of dramatically reducing the Company's projected equity infusions in order to achieve a lower equity ratio without a corresponding increase in the Company's debt balance to ensure that the Company's rate base is fully funded. Bleckman, 5 TR 1221. No other capital structure witness in this instant case, nor any recent cases, takes this approach in their positions. 5 TR 1221. Mr. Megginson eliminated the Company's projected equity infusions totaling $945 million without a corresponding increase to the projected long-term debt balance, thereby leaving the Company with a lower total capitalization. 5 TR 1222. This type of one-sided adjustment (in that it adjusts one side of a balanced equation but not the other) is contrary to sound ratemaking and financial planning principles. *Id*. In this case, Mr. Megginson is not objecting to the Company's total projected test year capital balance, but rather the relative portion of debt and equity that make up that balance. *Id*. In fact, Staff confirmed in its discovery response shown on Exhibit A-206 (MRB-15) that the Company's capital structure must include sufficient capital to fund the utility's rate base. *Id*. However, Mr. Megginson clearly disregarded this principle by projecting a total permanent capital balance (reflected on his Exhibit S-4, Schedule D-1) of $24.0 billion which is $400 million lower than the $24.4 billion projected by the Company on page 1 of Exhibit A-14 (MRB-1), Schedule D-1. *Id*. The one-sided nature of Mr. Megginson's adjustment thus results in a total cost of capital that is unfairly low. *Id*.

Mr. Megginson's reduction of the Company's equity balance without increasing long-term debt results in a lower total cost of capital than if he were to reduce equity and increase debt in equal amounts (Mr. Coppola's method discussed below). *Id*. This is because, in order to make

the Company whole, long-term debt and the associated cost of that debt would also need to be added to the Company's capital structure. *Id*. Failure to do so effectively assigns a capital cost of zero to the portion of the rate base not included in Mr. Megginson's capital structure. Mr. Megginson's failure to adjust debt and equity in equal amounts results in an overall pre-tax weighted average cost of capital that is approximately three basis points lower than it would be if he properly increased debt by the amount of his equity reduction. *Id*. In its discovery response shown on Exhibit A-206 (MRB-15) Staff acknowledges that "its approach results in a lower overall cost of capital as a simple matter of mathematics, i.e., equity cost more than debt and lowering the equity balance should lower the overall cost rate." *Id*. Mr. Megginson's one-sided adjustment does not fully compensate the Company for its total required capitalization and consequently disqualifies his proposed capital structure balances reflected on his Exhibit S-4, Schedule D-1 from being reasonably accepted by the Commission. *Id*.

Specifically, Mr. Megginson did not provide any analysis or reasoning, or frankly justification under law, that would support his one-sided approach to capital structure balancing. *Id*. In fact, in response to discovery on this issue shown on Exhibit A-206 (MRB-15), Staff admitted that "Staff has not commented on nor expressed concern with the Company's total projected permanent capital balance." *Id*. Staff further explained that "Staff's revision to the Company's equity infusion schedule should be viewed as Staff's objective to produce a 50/50 capital structure." *Id*. Staff therefore admits that its approach is outcome driven, and Staff apparently fails to realize that the one-sided nature of its adjustment unfairly and unjustly proposes to penalize the Company with a lower cost of capital compared to an approach that reduces equity in tandem with increased long-term debt. *Id*.

Staff has not consistently applied this one-sided approach in other utilities' rate cases. In Case No. U-21291, DTE Gas Company's recent rate case, Staff witness Joseph E. Ufolla explained that "[t]he difference between Staff and the [DTE's] Long-Term Debt and Common Equity balances is due to a difference in what [DTE] and Staff recommend as a reasonable equity ratio. Staff therefore shifts some of the proposed capital structure from the Common Equity layer to Long-Term Debt." Exhibit A-224 (MRB-33); 5 TR 1224. Mr. Ufolla also included a chart comparing the capital structure components as recommended by DTE Gas to those recommended by Staff. *Id*. While of course the long-term debt and equity balances are different between cases, the total capital structure balances are identical. *Id*. Mr. Megginson's one-sided approach to capital structure balancing not only lacks sound ratemaking principles and unfairly penalizes the Company with a lower cost of capital but is not consistently applied by Staff for other companies' capital structure development. *Id*. Because Staff made adjustments to the Company's capital structure without any, even remotely valid let alone substantial, evidence to support it, the Commission should reject Staff's proposed capital structure.

There is another error with Staff's calculation of the projected common equity balance. Staff's equity infusions shown in column (d) of Staff Exhibit S-4, Schedule D-5, page 1 (Common Equity Balance Forecast), are not reflected in the common equity balance (column (b)) in the month the equity infusions take place, but rather are added in the following month. *Id*. For example, Staff's projected $555 million equity infusion in February 2025 does not increase Staff's projected common equity balance until March 2025 (one month later). *Id*. Failing to reflect the equity infusion in the common stock balance until the month after it takes place is not only inaccurate, but it also serves to understate the projected common stock balance. 5 TR 1224-1225.

Staff's test year common equity balance should be $43 million higher to correct for this error. 5 TR 1225.

b. <u>The Commission Should Reject Staff's Argument that is in Favor of an Unreasonably Low Equity Ratio</u>

References in the Record: Bleckman, 5 TR 1225, 1229

Staff witness Megginson refers to Commission orders in previous rate cases, concluding that "the Commission desires to see a 50/50 capital structure submitted by the Company." In this proceeding, he then presents Staff's recommendation of 49.92%, which is of course lower than 50%. Bleckman, 5 TR 1225. Without any factual support, Staff apparently relied on interpretation of the Commission's orders from Case Nos. U-18124 and U-17990 for this position and then went lower than the purportedly aspirational capital structure. Staff's approach, however, is inconsistent with the Commission's Orders in those cases, as it is accomplished using artificial and unreasoned inputs, which are not supported by the record, which were not contemplated by the Commission in those orders, and which do not reflect the Company's unrebutted equity infusion plan – the substantial evidence in this proceeding on this issue.

In Case No. U-17990, the Commission first approached a discussion of balancing the Company's capital structure. The Commission, at that time, indicated an interest in moving the Company to a 50/50 capital structure but recognized that this may not be possible, saying that, in future cases, the Company should present an analysis explaining why its proposed capital structure would be more reasonable and prudent. February 28, 2017 Order, Case No. U-17990, page 64 ("U-17990 Order"). The Commission in its U-17990 Order recognized that there was a need, in <u>every case</u>, to continue to review the reasonableness and prudence of the capital structure. See U-17990 Order, page 64. This review, by the parties, and ultimately the Commission must be done upon substantial evidence on the record.

Notably, in Case No. U-17990, Mr. Megginson recommended a 10.00% ROE citing "remarkably stable" interest rates for a five-year period and recommended an equity ratio of 52.36%, with an overall rate of return of 5.86%, with all parties noting that economic conditions at that time were stable and that the general outlook for the industry indicated that capital costs would continue to be low. See U-17990 Order, pages 70, 71, and 75; see also Case No. U-17990, Exhibit S-4, Schedule D-1. The Commission, citing improvements in the Michigan economy, adopted a 10.10% ROE, a 52.87% equity ratio (after Staff agreed that it had failed to properly include a $125 million equity infusion that was planned for March 2016, but occurred in May 2016), and an overall weighted cost of capital of 5.94% -- all of which exceeded those recommended by Staff. See U-17990 Order, pages 60, 64, and 77. Two observations are important when reviewing the U-17990 Order. First, while the Commission directed the Company to present analyses explaining why its proposed capital structure would be more reasonable and prudent in future cases, it did not relieve Staff or any other party from presenting an analysis of the Company's actual capital needs, presenting an evidentiary case to demonstrate why it believes elements of the Company's capital structure are incorrect, unnecessary, or overstated, or presenting evidence to contradict the Company's contention that its proposed common equity balance and equity ratio will enable the Company to maintain strong credit ratings and better withstand shocks in the financial markets, thus ensuring efficient implementation of its capital expenditure program. Second, if the Commission solely relies on the U-17990 Order, as suggested by Mr. Megginson, the Commission should also observe that all of the economic conditions that existed at the time that resulted in Commission authorization of a 10.10% ROE, a 52.87% equity ratio, and an overall rate of return of 5.94%, have significantly deteriorated since 2020 due to the COVID-19 pandemic, the Ukraine/Russia conflict, a significant rise in interest rates, the banking crisis, rising inflation,

and the Israeli Middle East conflict. Based on these economic and market deteriorations, an equity ratio, overall rate of return, and ROE that are aligned with the Company's proposals in this case would be appropriate. As discussed further below, this is even more compelling in light of rating agency warnings of weakening credit metrics and subsequent downgrade by Moody's, which did not appear to be a risk in 2017.

Similarly, in its July 31, 2017 Order in Case No. U-18124 ("U-18124 Order"), wherein Staff proposed a 9.5% ROE, a 52.63% equity ratio, and an overall rate of return of 5.61%, the Commission disagreed and authorized a 10.10% ROE, an overall rate of return of 5.97% and an equity ratio of 53.1% (disagreeing with Staff's reduction in the Company's planned equity infusions). See U-18124 Order, pages 43-45, 52-53. As it relates to the Company's planned equity infusions and Staff's reduction in proposed equity infusions, which impacted the Company's common equity balance and reduced the proposed equity ratio, the Commission agreed with the ALJ who said:

> Consumers "undertook an analysis of the Company's actual expected capital needs during the test year in developing its recommended equity infusions, whereas Staff's recommendation has included no such analysis of the Company's actual capital needs and no evidence that the equity infusions were unnecessary or overstated." PFD, pp. 74-75. Similarly, the ALJ stated, the Staff provided no evidence to contradict Consumers' contention that its proposed common equity balance and equity-to-debt ratio will enable the company to maintain strong credit ratings and better withstand shocks in the financial markets, thus ensuring efficient implementation of its capital expenditure program. *Id.*, p. 75. [See U-18124 Order, pages 43, 45.]

The Commission made its decision to reject Staff's proposed equity ratio, ROE, and rate of return in favor of higher authorizations in Case No. U-18124 even though the Commission acknowledged that "Michigan's economy has improved considerably since Consumers' last contested rate case." See U-18124 Order, page 53. This Order, like the U-17990 Order, was issued

in 2017 and, in light of subsequent changes in the economy, shocks to the financial markets, and credit rating downgrade of the Company since that order was issued, suggests that the Company's proposals in this case are reasonable.

Staff references the Commission's U-20322 Order and U-20963 Order as support for Staff's proposed 50/50 capital structure and 9.85% ROE. The U-20322 Order was issued prior to the major global issues mentioned above that cause increased instability. The Commission issued the U-20963 Order after the Ukraine/Russia conflict began (February 2022), before interest rates began to rise (March 2022), before the banking crisis (March 2023 when three U.S. banks failed), and before the Israeli Middle East conflict rapidly escalated (October 2023). Thus, while Staff focuses on these previous Commission orders to justify unsupported adjustments to the Company's proposed capital structure, it fails to acknowledge that none of these Commission orders, or the Commission orders in the Company's subsequent rate cases, included requests or directives by the Commission that Staff make unsupported reduction to any inputs, including the Company's projected or actual equity infusions, to accomplish any such general or specifically-stated goal. In fact, in this case, Staff has not heeded the ALJ's criticisms of Staff's position on this issue in Case No. U-18124, which criticisms were adopted by the Commission in its U-18124 Order. Staff: (i) failed to include an analysis of the Company's actual capital needs; (ii) failed to provide any evidence showing that the planned equity infusions are unnecessary or overstated; and (iii) failed to provide evidence to contradict Consumers Energy's position that its proposed common equity balance and equity-to-debt ratio will enable the Company to maintain strong credit ratings and better withstand stresses in the financial markets, thus enabling efficient implementation of its capital expenditure program. See U-18124 Order, pages 43, 45.

Staff's continued push toward a 50/50, and now lower than 50/50, equity ratio regardless of the circumstances, relies on cases that predated numerous significant events that have negatively affected the Company's cash flow and have impacted supply chains to financial markets. Staff's position overlooks the Commission's direction that there is always a need for the Commission to review the reasonableness and prudence of the Company's capital structure based on the specific evidence in the particular proceeding at hand. Staff's unsupported focus on dictating a 50/50 (or lower) equity ratio ignores the reality of the Company's equity plan and unreasonably places the Company's credit at risk.

The Company's approach to projected equity infusions is well-reasoned analytically and supported by reality. Conversely, and as thoroughly explained above, Staff has provided no explanation or quantitative evidence to justify its request that the Commission artificially exclude the Company's planned equity infusions. Staff has also provided no explanation for its failure to increase the Company's projected long-term debt to offset its requested exclusion of planned equity infusions. Staff's resulting equity ratio does not adequately support the Company's credit and is another reason that the Commission should reject Staff's capital structure adjustments.

On behalf of Staff, Mr. Megginson consistently puts the cart before the horse in seeking to achieve a 50% equity ratio for the Company. Mr. Megginson suggests the Company lower its capital spending, but lower capital spending, in and of itself, will not improve credit metrics and credit quality. Bleckman, 5 TR 1229. As Mr. Bleckman pointed out, in this case the Company's proposed investment plan to ensure safe and reliable service to its customers will improve credit quality if done with a supportive level of equity capitalization and ROE, as the Company has proposed. *Id.* Mr. Megginson focuses on the Company's debt issuances to fund capital expenditures. *Id.* However, over half of the capital expenditures are also funded by equity. *Id.*

Additionally, reasonable and prudently recovered investments will generate operating cash flow, thereby increasing the FFO-to-Debt ratio. *Id.* Furthermore, Mr. Megginson completely disregards the corresponding use of proceeds from the debt issuance. *Id.* As reflected in this case, the Company is making necessary and significant investments in its operations which will improve utility infrastructure, enhance safety of aging assets, and ensure that customers receive the best service and value. Improving reliability, and other infrastructure investments, taken in whole, and the resulting increase in rate base and associated cash flows can have a positive impact on the Company's credit quality. *Id.*

c. <u>The Commission Should Reject Staff's Inaccurate Interpretation of the Credit Rating Agencies' Reports</u>

References in the Record: Bleckman, 5 TR 1227-1228

On page 7 of his direct testimony, "Mr. Megginson minimizes the importance of Moody's downgrade of the Company's credit rating by stating that the downgrade put the Company's credit rating more in line with the other two agencies ratings." Mr. Megginson also concludes that "the prior Moody's rating appeared to be an outlier." Mr. Megginson is mistaken on both counts. Each of the credit rating agencies maintains its own ratings methodology and credit rating scale. Bleckman, 5 TR 1227. It is not a universal measure in which the specific credit rating assigned by Moody's, for example, can be directly compared to the credit rating assigned by Standard and Poor's ("S&P") or Fitch. *Id.* If Mr. Megginson's assertion were true, there would not be a need for more than one rating agency, as all credit rating methodologies and credit rating scales would be the same.

Also, Mr. Megginson's attempt to downplay the credit ratings downgrade by implying that it was an inconsequential action should be rejected by the Commission. Each of the Company's debt offerings are rated by the three main rating agencies – Moody's, S&P, and Fitch. A lower

credit rating indicates higher risk which, in turn, necessitates a higher interest rate to compensate for that risk. *Id.* Regardless of the presumed comparative credit ratings between the different credit rating agencies, the fact that the Company's credit rating was downgraded by Moody's is a negative event that has negative financial consequences for the Company and for customers who bear the cost of capital. *Id.*

Staff downplays the importance of the Company's Moody's downgrade. Mr. Megginson points to the Company's debt issuances in 2021 and 2022 and projected debt issuances in this case as evidence that the Company has not been negatively impacted by Moody's credit rating downgrade. 5 TR 1228. Neither the Company's ability to issue debt in 2021 and 2022 nor the projection of continued debt issuances in this case is evidence that there have not been negative impacts from Moody's credit rating downgrade. As explained in Mr. Bleckman's rebuttal testimony, a lower credit rating results in negative financial impacts associated with a higher cost of capital. *Id.* In addition, the Company's debt issuances in 2021 and 2022 do not prove that the Company will undoubtedly have access to capital markets at reasonable rates in the future, especially with a lower ROE and equity ratio as proposed by Mr. Megginson. *Id.*

Mr. Meggison consistently misses the point that credit ratings play an important role in potential investors analysis of relative, or comparable, credit between businesses, i.e., utilities competing for investors' dollars. *Id.* While interest rates fluctuate, the ability to access credit markets at competitive rates is mainly dependent on the Company's credit quality and credit rating. *Id.* Specifically, Mr. Megginson's assumption that a potential decrease in interest rates ensures the Company's access to capital markets is misguided and should be disregarded by the Commission because it doesn't consider investors' alternatives. *Id.* Inflation and uncertainty surrounding interest rates will continue, affecting all utilities and not just the Company. *Id.* By

itself, a potential lowering of interest rates impacts the attractiveness of investing in the Company versus other utilities.

d. The Commission Should Reject the Attorney General's Proposed Adjustments to the Company's Equity Balance and Long-Term Debt Balance

References in the Record: Coppola, 5 TR 2785; Bleckman, 5 TR 1255-1256

Attorney General witness Coppola recommends that the Commission make a reduction of $183 million to the Company's equity balance in the test year and a corresponding increase in the Company's long-term debt balance by the same amount. See 5 TR 2785. The Attorney General's witness arrived at the $183 million amount for the adjustment based on an aspirational equity ratio of 50%. As also stated elsewhere herein, the Company is mindful of the Commission's Order in Case No. U-21389. At the same time, the Company must make its proposals to the Commission based on the circumstances, and the weighted rate of return as proposed in this case strengthens the Company's balance sheet and credit quality which will be critical in delivering the Reliability Roadmap investments while doing so in the midst of an elevated interest rate environment. Bleckman 5 TR 1255-1256.

To the Attorney General's credit, Mr. Coppola did not make the same one-sided adjustment error that Staff made. Nevertheless, the Commission should reject Mr. Coppola's proposals for all of the other reasons discussed above with respect to Staff.

i. The Commission Should Reject the Attorney General's Prospective Application of the notes in Moody's May 2024 credit opinion and S&P's August 2023 Credit Report

References in the Record: Bleckman, 5 TR 1256-1257

Mr. Coppola makes the false assumption that the Company is not at risk for a further credit rating downgrade based on based on the Company's FFO-to-Debt ratio in 2020 through 2024 being higher than the 18% threshold for Moody's and an actual FFO-to-Debt ratio of 18.7% in 2022 for

S&P. Mr. Coppola's assumption fails for two reasons. First, regardless of whether the Company falls below the thresholds, they are one factor but not the only factor that could lead to a further downgrade. Second, and as inclusive within the aforementioned reason, Mr. Coppola's assumption ignores the substantial fact that the Company's FFO-to-Debt ratios have been trending down irrespective of the downgrade thresholds at a particular time.

The Company's FFO-to-Debt ratio as calculated by Moody's has been trending down in recent years from 22.6% in 2021 to 19.1% in 2023. 5 TR 1256.

Moody's May 2024 credit report also shows a further decline to 18.7% for the 12 months ended March 2024. 5 TR 1256. While Moody's FFO-to-Debt ratios in previous years were higher than 18%, it is paramount to understand that the results cover a time when the Company's equity ratio was significantly higher than the 50% that Mr. Coppola recommended for the Company in this case, 52.7% in 2021, and 53.2% in 2022. And while the Company is again mindful of the Commission's Order in Case No. U-21389, without harming the Company's credit, the goal of a 50% equity ratio must bring with it some level of flexibility in practice given the extensive evidence Mr. Bleckman has presented in the record for this case. The stability of the Company's good credit quality in recent years is no guarantee of the Company's ongoing financial health. *Id.* The Company's FFO-to-Debt ratios achieved in previous years being above the level identified by Moody's that could give reason to a credit rating downgrade does not guarantee that the Company is not at risk for further credit rating downgrade in the future. 5 TR 1256-1257.

Likewise, while the Company's FFO-to-Debt ratio as calculated by S&P was 18.7% in 2022, the ratio has been trending down in recent years from 21.7% in 2021 to 17.6% in 2023, and S&P's August 2023 credit report referenced by Mr. Megginson states that the Company is expected to maintain an FFO-to-Debt ratio between 18% and 20%. 5 TR 1257. Therefore, the

Company's actual FFO-to-Debt ratio of 17.6% in 2023 was 40 basis points below the low end of S&P's expected range outlined in its 2023 report. *Id.*

Mr. Coppola's assumption fails first because, even if the Company's FFO-to-Debt ratio doesn't fall below the thresholds established by credit agencies, other factors, (e.g. the downward trend that has already been recognized by the credit agencies) could nonetheless lead to a further downgrade in the Company's credit. Mr. Bleckman's testimony makes clear that this is not mere speculation. It is however speculative and false to assume, as the Attorney General's witness does, that the adoption of an inadequate and predetermined equity ratio, regardless of the circumstances presented by the Company, will go unnoticed by the credit agencies and ultimately potential investors – investors in the state of Michigan, for purposes of the Reliability Roadmap in particular. The Commission should take note of the trend that the Company's FFO-to-Debt ratio have been on a steady decline and disregard the Attorney General's false assumption of credit stability. Sound businesses do not operate at the margin when it comes to credit stability, as a utility's credit is understood under the U.S. States Supreme Court *Bluefield* decision. The Company acknowledges the reasons the Commission has favored movement toward a 50% equity ratio in previous cases, but the Commission should reject the Attorney General's false assumption that the continued downward trend of the Company's equity ratio, even if above the credit agencies' thresholds, will not damage the Company's credit.

The stability of the Company's good credit quality in recent years is no guarantee of the Company's ongoing financial health. 5 TR 1256. The Commission should not lose sight of the reality that credit rating agencies provide insight to potential investors, who in turn, are making decisions on whether and where to invest their money. As conditions look less favorable in the state of Michigan, investors will put that money to use in other states. The Company acknowledges

that there will always be some access to capital, but not at a constant cost nor necessarily when needed by a business. Further, the standard under the *Bluefield* decision is not whether credit is available at all but whether authorized capital structure and ROE facilitate maintaining the utility's credit.

3. Consumers Energy's Financial Strength Is Crucial to Its Ability to Serve Customers

References in the Record: Bleckman, 5 TR 1193-1194, Exhibit A-14 (TAW-1), Schedule D-5

Company witness Bleckman testified on the interplay between the Company's equity ratio and ROE and how these two elements of the Company's capital structure directly affect how credit rating agencies view the financial strength of the Company. They are not the only considerations of credit agencies; however, he explained how these elements substantially inform rating agencies' decisions regarding the Company's credit rating which, in turn, impacts the Company's access to capital markets and access to financing at reasonable rates – the Company's credit.

Mr. Bleckman explained that this is important because the Company provides a critical service that directly impacts customers' quality of life and the Company's ability to deliver long-term investments to the infrastructure that provide safe, reliable, and clean energy will depend on the financial strength of the Company, of which the Company's credit rating is a key indicator. 5 TR 1193. As set forth in the testimony and exhibits of Mr. Bleckman and other Company witnesses, the Company is making significant capital investments to maintain and improve infrastructure to the benefit of customers. During this time, the Company must rely heavily on the capital markets to fund these investments. *Id.* Generally, a higher credit rating results in lower financing rates, i.e., a manifestation of better credit overall. Therefore, it will be especially important for the Company to maintain strong credit ratings over this period. *Id.* As shown in Exhibit A-14 (TAW-1), Schedule D-5, page 12, the Company has saved customers $141 million

annually as a result of improved credit ratings and lowered interest costs. Exhibit A-14 (TAW-1), Schedule D-5.

As Mr. Bleckman explained, the common equity balance and equity ratio projected for the test year in this case also enable the Company to maintain strong credit ratings and better withstand any stresses in the financial markets. 5 TR 1193. A current example of this was in March 2023, when Silicon Valley Bank and Signature Bank collapsed, forcing the Federal government to step in and take over the banks. 5 TR 1193-1194. Silicon Valley Bank marked the biggest failure of a United States bank since the 2008 global financial crisis and led to significant market turmoil. 5 TR 1194. Other large banks such as Credit Suisse and First Republic Bank also experienced significant financial pressure caused by the ensuing market panic. *Id.* In sum, better credit ratings allow a utility to still access funds and at better rates than they would otherwise get, especially in the face of stresses in the financial markets.

Strong credit ratings can help protect customers from spikes in interest rates which increase the cost of capital, and/or inaccessibility at particular times to the capital markets which serve as a key source of financing for the Company's capital expenditure program. 5 TR 1194. Strong credit ratings can also enable the Company to issue long-term debt ahead of upcoming maturities ("pre-fund") to take advantage of low interest rates and favorable issuance windows without jeopardizing the Company's financial ratios. *Id.* When market conditions are favorable, refinancing higher interest rate debt at lower rates reduces the Company's overall cost of capital included in customer rates. *Id.* The Company's ability to maintain its overall credit – its financial strength – is an important factor which directly affects its ability to strategically serve customers in this regard – potentially avoiding increases in, or capturing lower, overall cost of capital included in customer rates.

The Company's proposed capital structure, with an equity ratio of 50.75% and an ROE of 10.25% will provide rating agencies confidence that the Company is financially strong, and that the regulatory environment is supportive, which improves the Company's ability to obtain access to financial markets at reasonable rates, which in turn supports the Company's planned investments in infrastructure, and benefits customers. Likewise, financial strength sends a signal to would be investors that the state of Michigan is a solid investment, thereby potentially leading those invested dollars the Reliability Roadmap and other infrastructure investments that benefit customers. Furthermore, the Company's proposed capital structure, with an equity ratio of 50.75% and an ROE of 10.25% will likely prevent a downgrade to the Company's credit rating and help ensure it maintains its credit pursuant to the holding in the *Bluefield* case.

a. <u>The Company's Proposed Equity Ratio and ROE Produce an FFO-to-Debt Ratio that Rating Agencies Will View as supportive to the Company's Credit Quality, Which is Necessary to Obtain Access to Capital Markets and Financing at Reasonable Prices</u>

References in the Record: Bleckman, 5 TR 1190-1192

A key financial metric used by rating agencies is the ratio of FFO-to-Debt ratio. 5 TR 1191. An FFO-to-Debt ratio is a financial metric that compares a company's cash flow from operating activities to a company's leverage, or debt outstanding. *Id.* It can also be described as a type of payback ratio, reflecting the company's ability to repay its outstanding debt with operating cash flow. *Id.* A higher FFO-to-Debt ratio, one which reflects a higher level of cash flow from operating activities to offset or otherwise reduce the risk associated with the Company's ability to pay its debts, is viewed favorably and indicative of a lower financial risk and a resulting higher relative credit rating. *Id.* A higher credit rating, in turn, results in lower financing rates, which benefits customers. *Id.*

Because the calculation of this financial metric includes, in part, both the equity ratio and the authorized ROE of the Company, and FFO-to-Debt ratios are used by credit agencies to determine the Company's financial health, there needs to be a balance between the Company's equity ratio and ROE that will ensure that this key financial metric does not drop, cause significant credit deterioration, and threaten to impair the Company's access to capital markets and financing at reasonable rates. 5 TR 1190-1191. All else equal, lower authorized ROE would, therefore, necessitate a higher approved equity ratio to maintain the same level of financial health. 5 TR 1191. An equity ratio of 50.75% and an ROE of 10.25%, as recommended by the Company in this case, results in an FFO-to-Debt ratio that appropriately strikes this balance. 5 TR 1191-1192. Maintaining an authorized ROE of 9.90% without raising the approved equity ratio, however, may result in cash flow and credit metric deterioration. *Id.*

b. <u>Recent Reductions in the Company's Authorized Equity Ratios and ROEs Have Concerned Credit Rating Agencies, Leading to a Downgrade in the Company's Credit Rating and Continued Warnings of Additional Downgrades</u>

References in the Record: Bleckman, 5 TR 1192, 1197, 1273, and 1351, Exhibits A-39 (MRB-13), A-170 (TAW-8), A-171 (TAW-9)

As Mr. Bleckman noted in his direct testimony, there has been a sharp decline in the Company's authorized ROEs and equity ratios, and resulting authorized weighted rate of return, following several years of consistent results. 5 TR 1192, 1197. This directly led to a recent downgrade in the Company's credit rating by Moody's. Moody's May 2021 credit opinion cited declining authorized ROEs and regulatory capitalization as contributing to the downgrade. 5 TR 1351. Notably, Moody's specifically cited the Commission's December 2020 Order in Case No. U-20697, which authorized a 9.9% ROE and a 51.11% equity ratio, as one of the bases of its decision to downgrade the Company's credit rating. 5 TR 1351; Exhibit A-170 (TAW-8).

Like Moody's, in January 2021, S&P commented on the outcome of the Company's electric rate case in December 2020 (Case No. U-20697). 5 TR 1351. When referring to the equity ratio of 51.11% and ROE of 9.90% authorized in that case, S&P concluded that if these "lower ROEs and a lower equity ratio persist, credit quality could weaken." 5 TR 1351; Exhibit A-171 (TAW-9), page 3. S&P continued, saying "…we expect some modest weakening in financial metrics as a result of the recent electric rate case order…" Exhibit A-171 (TAW-9), page 4. Based on these comments, it is clear that the equity ratio of 51.11% and ROE of 9.90% were not considered supportive of the Company's credit quality and continuation at these levels or lowering further from these levels could negatively impact the Company's credit quality and credit ratings.

The credit agencies' concerns surrounding reductions in authorized equity ratios and ROEs are, in part, tied to their concerns that these authorized metrics force utilities to manage their financial positions with only minimal financial cushion – at the margin. As recent as February 2024, S&P said that having such a minimal financial cushion increases the susceptibility to a downgrade if an unexpected event occurs, that further weakens financial performance. Exhibit A-39 (MRB-13). Unexpected events include events such as the COVID-19 pandemic, the Ukraine/Russia conflict, rising interest rates, the banking crisis, rising inflation, and the Israeli Middle East conflict, which have all contributed to market volatility and market disruptions. These events, taken together with S&P's comments, highlight the importance of the Company maintaining strong financial metrics and not managing toward the perceived low end of the credit metric band. 5 TR 1197; 5 TR 1273. The Company is seeking an ROE and equity ratio that promote the Company's financial strength so that the Company can continue to make the necessary capital infrastructure investments to improve electric system reliability and resilience and, in turn,

provide customers with safe, reliable, and affordable electric service. The Commission should support the Company's proposed capital structure.

4. The Commission Should Reject the Reductions in the Company's Equity Ratio (and ROE) Proposed by Staff, the Attorney General and ABATE

Staff, the Attorney General, and ABATE fail to appropriately appreciate the importance of the Company's credit worthiness, the warnings of credit agencies, and the effects of market volatility and disruption in the past several years. These parties' recommendations for reductions in the Company's equity ratio and ROE would, if adopted from any of the three, seriously jeopardize the Company's ability to attract capital at reasonable rates – which is necessary to fund improvements in the Company's infrastructure and improve the reliability and resilience of the Company's electric system to better serve the Company's electric customers. The adjustments to the Company's proposed capital structure proposed by Staff, the Attorney General, and ABATE, including the Company's equity ratio and ROE, have no evidentiary basis, are results driven, and should be rejected by the Commission.

a. Staff Fails to Properly Consider the Relationship Between ROE, Equity Ratio, and Credit Metrics, and Staff's Proposed Equity Ratio and ROE Threaten to Cause Further Deteriorations in the Company's Credit Rating

References in the Record: Bleckman, 5 TR 1191-1192, 1230-1232, Exhibits A-14 (MRB-1), Schedule D-1

In his direct testimony, Mr. Megginson does not properly recognize the relationship between the Company's ROE, its equity ratio, and the Company's credit metrics. Thus, Staff does not give a holistic picture of how the Company's credit health is determined.

To understand how credit agencies evaluate a utility, it is important to understand and evaluate the interplay between the Company's equity ratio and ROE. As Mr. Bleckman explained, multiplying the equity ratio by the ROE produces a weighted cost or weighted "rate of return."

This is shown on Exhibit A-14 (MRB-1), Schedule D-1, page 1. 5 TR 1231. Exhibit A-14 (MRB-1), Schedule D-1. The weighted rate of return is a key determinant of the Company's ratio of FFO-to-Debt, which is used by credit agencies to determine the Company's financial health. 5 TR 1232. Consequently, it is important to recognize that the Company's ROE and equity ratio cannot be evaluated separately and in isolation, but should, instead, be viewed as interconnected components that heavily influence the Company's overall financial health. 5 TR 1191.

An ROE of 10.25%, when taken together with an equity ratio of 50.75% results in weighted rate of return equal to 5.20%, which is better aligned with rate of return levels prior to the Company's credit rating downgrade in 2021 and is, therefore, supportive of adequate credit quality at this time. 5 TR 1192. A lower authorized ROE would necessitate a higher approved equity ratio to maintain the same level of financial health. *Id.*

On page 10 of his direct testimony, Mr. Megginson uses data from the Company's Form 10-K filed with the Securities & Exchange Commission ("SEC") to calculate the Company's FFO-to-Debt ratio. Bleckman, 5 TR 1230. Mr. Megginson uses a S&P formula to calculate a 18.87% FFO-to-Debt ratio for 2023. *Id.* However, Mr. Megginson's FFO-to-Debt calculation is significantly overstated. *Id.* S&P does not simply take data from the Company's SEC filings, but rather starts with that data and then layers in numerous adjustments to calculate the FFO-to-Debt ratio. *Id.* S&P includes power purchase agreements ("PPAs"), asset retirement obligations, and leases as additional debt when calculating credit metrics. *Id.* For example, S&P imputed $358 million in additional debt related to PPAs and $584 million in additional debt for asset retirement obligations in 2023. *Id.* When S&P increases debt by including these items, the ratio of FFO-to-Debt used to evaluate the Company's credit worthiness is thereby lowered. *Id.* By itself, this shows that Mr. Megginson's FFO to debt calculation is significantly overstated and is

evidence that his credit metric calculations and guidance should be disregarded by the Commission. *Id.*

The Company's actual FFO-to-Debt ratio as calculated by S&P for 2023 is on page 5 of S&P's August 20, 2024 Credit Report on Exhibit A-207 (MRB-16). S&P calculated an FFO-to-Debt ratio for the Company of 17.6% in 2023, 127 basis points lower than calculated by Mr. Megginson. 5 TR 1230. Since Mr. Megginson's estimated FFO-to-Debt ratio for the Company in 2023 was significantly overstated as evidenced by S&P's credit report, his calculations, and any conclusions stemming from these calculations, cannot be relied upon. *Id.*

On page 11 of his direct testimony, Mr. Megginson then concludes that "ratings agencies don't foresee any major deterioration or long-lasting decline in the FFO-to-Debt ratio for Consumers Energy." 5 TR 1231. Mr. Meggison attempts to support this conclusion by referencing rating agency reports in which S&P expects the Company to maintain an FFO-to-Debt ratio between 18% and 20% over the next three to five years and Moody's expects the Company's FFO-to-Debt ratio to average 20% to 21%. *Id.* However, these rating agency references are not supportive of Mr. Megginson's conclusion.

First, refer to page 5 of S&P's August 20, 2024 Credit Report shown on Exhibit A-207 (MRB-16). The Company's FFO-to-Debt ratio as calculated by S&P has been trending down in recent years from 21.7% in 2021 to 17.6% in 2023, a decrease of 410 basis points and, for 2023, 40 basis points below the low end of S&P's expected range outlined in its 2023 report. 5 TR 1231. In addition, refer to page 2 of Moody's May 31, 2024 Credit Report shown on Exhibit A-208 (MRB-17). The Company's FFO-to-Debt ratio as calculated by Moody's has also been trending down in recent years from 22.6% in 2021 to 19.1% in 2023, a decrease of 350 basis points. *Id.* Moody's May 31, 2024 Credit Report also shows a further decline to 18.7% for the 12 months

ended March 2024. *Id.* It is clear from this report that the Company's FFO-to-Debt ratio as calculated by Moody's is trending down and was well below the low end of Moody's expected range (20-21%) for the Company for 2023 and so far in 2024. *Id.*

While Mr. Megginson highlights the FFO-to-Debt ranges expected by rating agencies, there is no assurance that the Company will ultimately achieve these levels. 5 TR 1232. Recent rate cases have resulted in a sharp decline in weighted rate of return (again, ROE multiplied by equity ratio). 5 TR 1232, 5 TR 1192. In addition, Mr. Megginson proposes an even lower ROE and equity ratio in this case. 5 TR 1232. A reduction in the Company's rate of return lowers cash flow, increases debt, and thereby weakens the Company's FFO-to-Debt ratio. *Id.* These negative credit metric impacts place the Company's credit quality and credit ratings at risk. *Id.* The equity ratio and ROE combination, and therefore the implied weighted rate of return, recommended by Staff is clearly unsupportive of the Company's credit quality and should be rejected.

i. Staff Fails to Accurately Assess the *Present* Regulatory Environment; The Commission Should Not Adopt Staff's Rosy Outlook Because it is Contrary to the Evidence

References in the Record: Bleckman, 5 TR 1232-1234, Exhibit A-40 (MRB-14)

In his testimony, Mr. Megginson describes the impact of the Company's regulatory environment on its credit rating. 5 TR 1232. Mr. Megginson also references credit reports in which the Company's regulatory environment has been described as positive, in an attempt to support his recommendation to reduce the Company's equity ratio to 49.92% for the test year in this proceeding. *Id.* However, Mr. Megginson's assessment of the Company's regulatory environment is largely incomplete. In his testimony, Mr. Megginson focuses on aspects of Michigan's regulatory framework that have been established for several years under the 2008 and 2016 energy legislation, including items such as the 10-month rate case process. *Id.* Mr. Megginson's assessment fails to capture the results from the Company's most recent rate cases

which demonstrate a sharp decline in authorized weighted rate of return following a long period of stability. 5 TR 1233. This recent shift is illustrated in the table on page 14 of Mr. Bleckman's direct testimony. In addition, the credit agencies rating of states' regulatory environments is continuously evaluated. *Id.*

The persistent decline in the Company's authorized weighted rate of return since 2020 could, and likely will, be seen as a material deterioration in the credit supportiveness of the Michigan regulatory environment. 5 TR 1233. Mr. Megginson fails to acknowledge that the Company's positive regulatory environment in past years had been fueled in large part by authorized ROE and equity ratios that were significantly higher than currently proposed by Staff for the Company in this case. *Id.* In fact, the trend in rate orders with regard to authorized ROE and equity ratio was a cause for concern for Moody's in its downgrade of the Company's credit rating. *Id.* An equity ratio of 50.75% and an ROE of 10.25% is better aligned with rate of return levels prior to the Company's credit rating downgrade and is therefore supportive of adequate credit quality at this time. *Id.*

There is evidence that analysts have started to recognize a decline in the state of the Company's regulatory environment. 5 TR 1233. In updating its regulatory rankings for U.S. utilities in May 2023, UBS moved Michigan down a level from Tier 1 to Tier 2. *Id.* In describing the negative change, UBS specifically mentioned authorized ROEs as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." Refer to Exhibit A-40 (MRB-14). It is apparent that rating agencies and analysts have taken note of the recent trend in the Company's regulatory outcomes with regard to capital structure and ROE. 5 TR 1233-1234. A continuation or, even worse, a further degradation of the authorized equity ratio and ROE puts the Company at risk of dropping

further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating. 5 TR 1234. Michigan's regulatory standing needs to be protected and bolstered rather than drawn upon to push the Company toward over-leveraging. 5 TR 1234. Broadly speaking, above average regulatory standing translates into increased potential investment which continues to support affordable utility infrastructure financing for the state of Michigan. *Id*.

ii. Staff Fails to Accurately Assess the *Present* Macro-Economic Conditions; The Commission Should Not Adopt Staff's Rosy Outlook Because it is Contrary to the Evidence

References in the Record: Bleckman, 5 TR 1235-1236, Exhibit A-39 (MRB-13)

Despite the rosy picture painted by Mr. Megginson, S&P provided additional insight with regard to the future credit quality of regulated utilities including Consumers Energy. Exhibit A-39 (MRB-13). In a February 2024 report "Rising Risks: Outlook for North American Investor-Owned Regulated Utilities Weakens," S&P updated their outlook of the regulated utility industry to negative. S&P cites the high percentage of utilities with negative credit outlooks and expects that 2024 will likely be the fifth consecutive year that credit downgrades outpace upgrades. In its report, S&P cites "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus equity. In Exhibit A-39 (MRB-13), page 10, S&P states that "for 2023, the industry's actual equity issuance was considerably below our expectations, resulting in a weakening of financial performance and credit quality. If this trend persists, credit quality will again likely experience pressure in 2024."

Of particular concern, to both the Company and potentially its customers, S&P also notes utilities as having "strained financial cushion." Specifically, S&P states:

> About 35% of the industry is sustaining performance with minimal financial cushion, reflecting funds from operations (FFO) to debt that is less than 100 basis points (bps) above their downgrade threshold. The limited financial cushion affects a company's ability

> to absorb unexpected events beyond the base case for our ratings, increasing its susceptibility to a downgrade. [Exhibit A-39 (MRB-13), page 9.]

In addition, S&P cites the following credit headwinds impacting regulated utilities:

- Upcoming debt maturities amid higher interest rates, weakening financial performance;
- A narrowing spread between U.S. Treasuries and authorized ROEs which directly hinders the financial performance; and
- Elevated inflation rates resulting in higher costs that, given regulatory lag, could weaken financial performance. 5 TR 1235.

S&P's assessment of the regulated utility industry was echoed by another credit rating agency, Fitch, in December 2023. *Id.* In describing a "deteriorating outlook for North American utilities, power & gas in 2024," Fitch cited similar credit headwinds that are putting pressure on utilities' credit metrics. *Id.* Specifically, Fitch concluded that "the sharp escalation in interest rates has significantly narrowed the headroom in Funds from Operation ('FFO') fixed-charge coverage for the sector." *Id.*

These rating agency reports highlight macro-economic conditions that make it important for an equity ratio higher than either 50% or Staff's 49.92% position. 5 TR 1236. It is apparent from these rating agency reports that a weighted equity return, (the product of the ROE and equity ratio) higher than the current authorized level, and certainly higher than the continued degradation proposed by Staff, is critical to protect the Company from receiving a credit downgrade in the event of circumstances such as the prevailing high interest rate environment, as specifically described above. *Id.* Additionally, the Commission has spoken in recent orders of a "willingness to accept a temporary deviation from a balanced capital structure over the short-term when circumstances warrant such an approach" (Case No. U-20963), and certainly the prevailing high interest rate environment, and the macro-economic conditions described above, present just such a circumstance. *Id.*

iii. Staff Chooses to Ignore the Possibility of Another Credit Downgrade and Presents No Analysis or Discussion of the Impacts of a Credit Downgrade on the Company and its Customers; Therefore, The Commission Should Disregard Staff's Recommendations that Could Lead to a Credit Downgrade

References in the Record: Bleckman 5 TR 1237-1238, Exhibit A-14 (TAW-1), Schedule D-5

Despite Staff's relative silence on the matter, the effect of another credit downgrade could be very bad for the Company and its customers.

Lowering the Company's equity ratio and authorized ROE reduces the Company's overall rate of return. 5 TR 1237. This, in turn, lowers the Company's cash flow and FFO-to-Debt ratio. *Id.* The Company then has to increase its long-term debt to achieve a lower equity ratio thereby weakening the Company's FFO-to-Debt ratio. *Id.* The negative impacts could cause the Company's FFO-to-Debt ratio to drop below the established rating agency thresholds, placing both the Company's credit quality and credit ratings at risk. *Id.*

While it may seem attractive for customers in the near-term to reduce the equity layer of the Company, such a move, and the potential resulting credit rating downgrade, could lead to the Company's customers paying higher financing costs over the long term, and it could put at risk the Company's ability to execute on its critical investment plan on behalf of customers. 5 TR 1237. Thus, it is of great importance for the regulatory response to be balanced and thoughtful as the financial health of the Company is a critical element of its ability to implement the capital plan needed to deliver safe, reliable, and clean energy to its customers. 5 TR 1237-1238.

To the contrary, a higher credit rating ensures that the Company is able to obtain financing at lower interest rates, resulting in long-term customer rate stability. 5 TR 1238. As shown in Exhibit A-14 (TAW-1), Schedule D-5, page 12, the Company has saved customers $141 million annually as a result of improved credit ratings and lowered interest costs. But the customer benefits

extend far beyond this long-term rate stability. *Id.* The Company is making significant capital investments to maintain and improve utility infrastructure to improve reliability and resiliency to the benefit of customers. *Id.* During this time, the Company must rely heavily on the capital markets to fund these investments. *Id.* Therefore, it will be especially important for the Company to maintain strong credit ratings to ensure beneficial access to capital markets for funding to deliver these critical customer investments and enable the Company to do so at the lowest possible financing cost on their behalf. *Id.*

iv. Staff Fails to Appropriately Consider the Average Equity Ratio of Peer Group Companies; Therefore, The Commission Should Reject Staff's Analysis

References in the Record: Bleckman, 5 TR 1238-1241, Exhibit A-36 (MRB-10)

Mr. Megginson's recommended 49.92% equity ratio is significantly lower than equity ratios authorized by other commissions. Bleckman, 5 TR 1238. Mr. Bleckman researched all rate case decisions from 2020 through March 2024 of peer companies and determined the authorized or approved equity ratio for each. 5 TR 1238-1239. His analysis is reflected on Exhibit A-36 (MRB-10). The average authorized equity ratio for the peer group was 53.32%, 340 basis points higher than the 49.92% proposed by Mr. Megginson for Consumers Energy in this case. 5 TR 1239.

In setting a proper return, the standard under the U.S. Supreme Court's holding in *Bluefield* relies on the concept of "*corresponding risks and uncertainties*" *Bluefield*, supra, 262 US at 692, *emphasis added*. Beyond a prescription under the Fourteenth Amendment to the Constitution, it is appropriate to consider peer company equity ratio averages and trends in determining the appropriate equity ratio for the Company. 5 TR 1241. The Commission has recognized this appropriateness. In its Order in Case No. U-20963, the Commission cited Staff's average ROE analysis as one of the factors considered in determining the Company's approved ROE. *Id.* In

addition, in Case No. U-21389, the ALJ also considered average authorized ROEs in determining the appropriate ROE for the Company. *Id.* In its order, the Commission found that the ALJ "appropriately considered the record evidence of each party" with regard to ROE. *Id.* It is apparent that the Commission considers peer averages an important piece of evidence to inform the ratemaking process. *Id.* To be consistent with that philosophy, it is appropriate to consider peer company equity ratio averages and trends in determining the equity ratio for the Company in this case. *Id.*

The equity ratios that Mr. Bleckman used, as reflected on Exhibit A-36 (MRB-10), are based on commission-authorized equity ratios, not historical financial data. 5 TR 1239. They represent actual regulatory equity ratios authorized or approved by the various commissions across the country, as specifically requested by the Commission on page 218 of its Order in Case No. U-20963. *Id.* It is clear from this analysis that, on average, regulatory commissions of the Company's peer group are granting equity ratios that are much higher than the 50.75% requested by the Company in the current case, and higher still than the 49.92% equity ratio chosen by Mr. Megginson. *Id.*

Despite this higher peer average, the Company proposes a modest ratio of 50.75%, which balances the higher peer average with capital investment plans, credit metrics, customer rate impacts, and the guidance of this Commission, and which continues to support affordable utility infrastructure financing for the state of Michigan. 5 TR 1239. This proactive balancing, which is based upon peer review, conducted by the Company, is precisely reflective of a successful regulatory compact as outlined in the *Bluefield* decision. The Commission should applaud the Company's efforts and should reject any shortsighted attempt to arbitrarily deflate the Company's equity ratio.

However, Mr. Megginson, on behalf of Staff, took a different path. On page 2 of his Exhibit S-4, Schedule D-5, Mr. Megginson calculated an average authorized equity ratio of 52.68%. This is 276 basis points higher than Mr. Megginson's recommended equity ratio in this case of 49.92% and 193 basis points higher than the Company's recommended equity ratio in this case of 50.75%. Bleckman, 5 TR 1240. But even this 52.68% equity ratio result is deflated.

According to Mr. Megginson's exhibit, the source of the equity ratio data is S&P Global Market Intelligence. 5 TR 1240. S&P Global Market Intelligence tracks the authorized equity ratio as a percentage of total capitalization. *Id.* Total capitalization can be higher (thereby under reporting an equally comparable equity ratio) because, in addition to permanent capital components, items such as short-term debt, deferred taxes, and customer deposits can be included. *Id.* For example, as reflected on Exhibit A-14 (MRB-1), Schedule D-5, the Company's 50.75% permanent equity ratio in this instant case translates to only 42.36% on a total capitalization basis that would be reported in Staff's referenced database, which is a difference of 839 basis points. *Id.* The Company's equity ratio, which is based on a percentage of permanent capital, should only be compared to equity ratios of peer utilities based on percentage of permanent capital in order for the comparison to be at all meaningful. *Id.* Furthermore, Mr. Megginson's approach is directly contradictory to the Commission's direction in the U-20963 Order, page 218, that comparisons to other utilities' equity ratios should be based solely on equity ratios set by a regulatory commission in a rate case. The actual commission authorized equity ratios provide the required data for a comparable analysis and were relied upon in Company witness Bleckman's analysis shown in Exhibit A 36 (MRB-10) which shows the average equity ratio for the peer group utilizing this method to be 53.32%. *Id.* This analytical result is nowhere near Mr. Megginson's recommendation.

The Commission should reject Staff's recommendation and instead rely on the substantial evidence – the facts on the record in this proceeding. Otherwise, an adopted recommendation that is so far from peer utilities cannot be consistent with the U.S. Supreme Court's holding in *Bluefield*.

v. In Summary, Staff has Provided No Substantial Evidence in Support of an Equity Ratio at or Near Staff's Recommendation; therefore, The Commission Should Reject Staff's Recommendation in Favor of the Company's

References in the Record: Bleckman, 5 TR 1242

The Company has shown that Staff's position on equity ratio is largely not evidence-based and that the evidence which Mr. Megginson does provide is unsound and underestimates results. Mr. Megginson's faulty approach to capital structure projection of decreasing equity without a counterbalanced increase to debt should be regarded as disqualifying. Bleckman, 5 TR 1242. The Company has also shown that Staff's recommended equity ratio for the test year in this case is below what is considered supportive of the Company's credit quality and also significantly lower than the average equity ratio of peer group companies. Finally, despite Mr. Megginson's own analysis to the contrary, Staff claims to support a "balanced" 50/50 split capital structure and then goes on to propose an equity ratio below 50%. For these reasons, Staff's recommended equity ratio of 49.92% for the test year in this case, or any ratio near it, should be rejected.

b. The Attorney General's Proposed Equity Ratio and ROE Threaten to Cause Further Deteriorations in the Company's Credit Rating

i. There is No Merit to the Attorney General's Attempt to Discredit the Company's Credit Metric Analysis

References in the Record: Bleckman, 5 TR 1256-1257, Exhibit A-164 (TAW-2)

Mr. Coppola references Moody's May 31, 2024 Credit Report, noting that the Company's FFO-to-Debt ratio in 2020 through 2024 were higher than the 18% listed by Moody's. The 18%

represents one factor that could lead to a further downgrade should the Company's FFO-to-Debt ratio fall below that level. 5 TR 1256. Mr. Coppola also references the August 2023 credit report from S&P which lists the Company's FFO-to-Debt ratio in 2022 as 18.7%. Mr. Coppola makes these references for the proposition that the Company is not at risk for further credit rating downgrade. However, as Mr. Bleckman explained in his rebuttal testimony to Staff witness Megginson, the Company's FFO-to-Debt ratio as calculated by Moody's has been trending down in recent years. *Id.* Moody's May 31, 2024 Credit Report also shows a further decline for the 12 months ended March 2024. This trend is concerning and risky for the Company's credit regardless of the particular threshold.

The trend is doubly important because, although Moody's FFO-to-Debt ratios in previous years were higher than 18%, the results cover a time when the Company's equity ratio was significantly higher than Mr. Coppola recommends for the Company in this proceeding. 5 TR 1256. The Company's equity ratio was 52.7% in 2021 and 53.2% in 2022. *Id.* The stability of the Company's good credit quality in past years is no guarantee of the Company's ongoing financial health. *Id.* In particular, the Company's FFO-to-Debt ratios achieved in previous years being above the Moody's thresholds does not guarantee that the Company is not at risk for further credit rating downgrade in the future. 5 TR 1256-1257. Mr. Coppola attempts to minimize the appearance of increased risk, but ratings analysts and potential investors are savvy enough to look at the Company's current and potential future financial health. The Commission should reject the Attorney General's attempt to downplay the risk of a further downgrade to the Company's credit rating.

The same holds true in regard to S&P. As Mr. Bleckman addressed in response to Staff, while the Company's FFO-to-Debt ratio as calculated by S&P was 18.7% in 2022, the ratio has

been trending down in recent years from 21.7% in 2021 to 17.6% in 2023. 5 TR 1257. In addition, S&P's August 2023 credit report referenced by Mr. Megginson states that the Company is expected to maintain an FFO-to-Debt ratio between 18% and 20%. *Id.* Therefore, the Company's actual FFO-to-Debt ratio of 17.6% in 2023 was 40 basis points below the low end of S&P's expected range outlined in its 2023 report. *Id.* These trends are not unnoticed nor harmless, despite the lack of concern expressed by Mr. Coppola.

Attorney General witness, Mr. Coppola, criticizes the Company's mathematical development of how ROE and equity ratio determine a company's FFO-to-Debt in line with Moody's ratings methodology shown on page 9 of Mr. Bleckman's adopted direct testimony and in Exhibit A-164 (TAW-2) due to the absence of deferred income tax and an understated depreciation component. 5 TR 1257. However, Mr. Bleckman's analysis in Exhibit A-164 (TAW-2) likely overstates the long-term FFO-to-Debt metric as calculated by rating agencies, since they make a number of additional adjustments to the Company's metrics for items to include PPAs, pension obligations, asset retirement obligations, securitization debt, and operating leases – all of which would generally lower the FFO-to-Debt metric. *Id.* Because the Company invests in long-lasting projects and assets, and the Commission has focused on the Company's ROE and equity ratio at a level that support the long-term credit metrics of the business, the Company's recommended ROE of 10.25%, and the Company's proposed 50.75% equity ratio, and the analysis that supports them, is rightfully supportive of the Company's long-term credit. *Id.* Mr. Coppola's attempt to discredit the Company's analysis by these means is without merit.

ii. Mr. Coppola's Analysis Contains Fatal Flaws and Must Be Rejected

References in the Record: Bleckman, 5 TR 1258-1261; Coppola, Exhibit AG-1.19

In his rebuttal testimony, Mr. Bleckman pointed out that Mr. Coppola mixes the Company's authorized ROE with the Company's earned ROE, which greatly distorts the pro forma FFO-to-Debt impacts. 5 TR 1258. Mr. Coppola calculated the Company's actual earned ROE for 2023 at 8.26%. *Id.* As described more fully in Mr. Bleckman's rebuttal at page 41, Mr. Coppola's mixing leads to the conclusion that if the Company's authorized ROE in 2023 was lower, the Company's FFO would have been higher. This is nonsensical and thus results in a pro-forma FFO-to-Debt ratio that is both invalid and significantly overstated. Therefore, Mr. Coppola's pro-forma FFO-to-Debt analysis for Moody's in 2023 should be rejected by the Commission.

Mr. Coppola also makes an unsupported and inaccurate assertion that equity investments into the Company from Consumers Energy's parent company, CMS Energy, are the result of CMS Energy borrowing debt and investing the proceeds into the Company. 5 TR 1259. As the Company has repeatedly explained in this proceeding (and others), the timing and amounts of long-term debt and equity issued by CMS Energy have no bearing on the timing and amount of equity infusions made into Consumers Energy. *Id.* CMS Energy determines equity infusions after considering the capital spending and financing needs of Consumers Energy. *Id.* The goals of the parent company include maintaining a strong and healthy utility, capable of serving the needs of its customers, and this commitment is reflected in the equity infusions from the parent company to Consumers Energy over the last several years and the resulting actual equity ratio. *Id.*

Despite that the timing and amounts of long-term debt and equity issued by CMS Energy have no bearing on the timing and amount of equity infusions made into Consumers Energy, Mr. Coppola also provides an analysis of the capital structure of CMS Energy and Consumers

Energy from 2010 to 2023, in an attempt to link changes in long-term debt and equity between the two companies. In Case No. U-18124, the Attorney General made this same argument that Consumers Energy's equity balance is, at least in part, funded by long-term debt from its parent company. In its July 31, 2017 Order in Case No. U 18124, the Commission adopted the findings and recommendations of the ALJ, who determined this argument from the Attorney General "has been considered and rejected by the Commission." Mr. Coppola's analysis has been found to have no merit in the past, continues to have no merit, and should again be rejected.

The results of his analysis showing a 43.7% average equity ratio for his ROE proxy group is not an appropriate comparison to the projected common equity ratio in this case. Bleckman, 5 TR 1260. The average equity ratio calculation for the proxy group on Mr. Coppola's Exhibit AG-1.19 uses the equity ratio at the parent holding company level and is, thus, a misleading and inappropriate comparison. *Id.* As the Company has repeatedly explained in response to this exact same argument by the Attorney General over the years, ratios at the parent holding company level may be distorted by other, non-regulated balance sheet items and provides a completely inappropriate point of comparison. Without an extremely strong and accompanying rationale, one would think that the 630 basis point differential between the results of his analysis on his Exhibit AG-1.19 and his own recommendation, would give Mr. Coppola some recognition that the analysis does not provide a relevant comparison.[11] *Id.* Though, Mr. Coppola continues to avoid addressing this discrepancy. The results do provide an extremely low number however, even if a complete inappropriate comparison. The Commission should reject it outright.

[11] In his rebuttal testimony, Mr. Bleckman notes that Mr. Coppola's analysis is further skewed because the sources for Mr. Coppola's debt and equity balances are SEC reported financial statements, which are prepared under Generally Accepted Accounting Principles ("GAAP"). There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis. 5 TR 1260.

Mr. Coppola's average peer group equity ratio analysis is inconsistent with the Commission's Order in Case No. U-20963. 5 TR 1261. The Commission stated that "regulatory and financial data should not be combined" with such an analysis. Further, the Commission deemed in its Order in Case No. U-20963 that such an analysis is invalid assuming one "could not verify that its data contained equity ratios set by a regulatory commission in a rate case." In his analysis of a proper equity ratio for the Company, Mr. Coppola ignores the Commission's reasoned finding by consistently utilizing equity ratios based, in part, on financial, and not regulatory, data. *Id.* He also consistently utilizes equity ratios that do not arise out of commission orders, and he further fails to explain the basis or rationale for doing so. As a result, the Commission should reject the Attorney General's equity ratio analysis in its entirety. It is contrary to explicit Commission findings and thus provides no reliable evidence in this proceeding.

c. ABATE's Proposed Adjustments to the Company's Capital Structure are Erroneous and Should Be Rejected by the Commission

i. ABATE's Proposed Authorized Common Equity Ratio of 50.0% is Inconsistent with its Witness's Own Data, is Established Using a Source that Improperly Understates Equity Ratios, was Established in a Manner that is Contrary to Commission Findings, and Ultimately Only Supports an Increase to the Company's Equity Ratio

References in the Record: Bleckman, 5 TR 1270-1276, Exhibits A-36 (MRB-10) and A-39 (MRB-13); Walters, 5 TR 3376-3377, 3394, Exhibit AB-8; Coppola, Exhibit AG-1.19

ABATE witness Mr. Walters recommends a 50.0% equity ratio. Bleckman, 5 TR 1271. Despite his recommendation, as shown in Mr. Walters' Table CCW-2 (Walters, 5 TR 3376-3377), the average equity ratio in his analysis has increased from 49.70% in 2016 to 50.84% in 2024. The trend is clearly upward. In fact, Mr. Walters' table shows that the Company's projected equity ratio of 50.75% in this case is below industry averages for all years listed. Mr. Walters' table

shows that his recommended equity ratio for the Company in this case of 50% is significantly understated when compared to his own calculation of industry average equity ratios and the upward trends. Bleckman, 5 TR 1270-1271. This is yet another instance of an Intervening Party completely ignoring the factual evidence in this proceeding. ABATE's recommendation is not supported by substantial evidence. Thus, the Commission should reject it.

If that was not enough to dispose of ABATE's recommendation, the average equity ratios reflected in Mr. Walters' Table CCW-2 are understated to boot. 5 TR 1271. The source of his equity ratio data is "S&P Global Market Intelligence." *Id.* S&P Global Market Intelligence tracks the authorized equity ratio as a percentage of total capitalization. *Id.* Total capitalization can be higher (making the equity ratio lower) than permanent capitalization because, in addition to permanent capital components, items such as short-term debt and customer deposits can be included. *Id.* As described Mr. Bleckman's rebuttal of Staff witness Megginson, the Company's proposed equity ratio in this instant case as a percentage of total capitalization is 42.36%, significantly lower than the 50.75% proposed as a percentage of permanent capitalization. *Id.*

Again, in order to make valid comparisons, the Company's equity ratio, based on a percentage of permanent capital, should be compared to utilities also using an equity ratio based on percentage of permanent capital. 5 TR 1271. By utilizing utility equity ratios that are based on a percentage of total capitalization to support his recommended equity ratio for the Company in this case, Mr. Walters is not making a direct like-for-like comparison at all, and thereby understating his results, which are already higher than the Company's request. *Id.*

Mr. Bleckman explained that actual Commission authorized equity ratios is the preferred data source for an average equity ratio analysis. 5 TR 1271-1272. In Exhibit A 36 (MRB-10), Mr. Bleckman researched all rate case decisions from 2020 through March 2024 of peer regulated

companies and determined the authorized or approved equity ratio for each. 5 TR 1272. Consistent with the Commission's Order in Case No. U-20963, the equity ratios that Mr. Bleckman used for comparison purposes were taken from commission orders and public filings and represent actual regulatory peer equity ratios authorized or approved by different commissions across the country. 5 TR 1271. It is worth stating again, the average equity ratio for the peer group was 53.32%. While ultimately seeking balance that is provided by the Company's 50.75% proposal, this is significantly higher than that and is also 332 basis points higher than the equity ratio Mr. Walters recommends for the Company in this in this proceeding. 5 TR 1272.

Mr. Walters presents S&P ratings data from 2009 to 2024 in Table CCW-3 in an attempt to show that regulated utility companies have been able to maintain relatively strong credit ratings during periods of declining authorized ROEs. However, given the U.S. Supreme Court's holding in the *Bluefield* decision, it is not a justification to lower a utility's ROE. In any event, S&P commented recently on the credit quality of utilities. On page 15 of Mr. Walters's direct testimony, he highlights a February 2024 report "Rising Risks: Outlook for North American Investor-Owned Regulated Utilities Weakens," in which S&P updated its outlook of the regulated utility industry to negative. S&P cites the high percentage of utilities with negative credit outlooks and expects that 2024 will likely be the fifth consecutive year that credit downgrades outpace upgrades. 5 TR 1272. In its report (Exhibit A-39 (MRB-13)), S&P cites "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus equity. S&P states that "for 2023, the industry's actual equity issuance was considerably below our expectations, resulting in a weakening of financial performance and credit quality. If this trend persists, credit quality will again likely experience pressure in 2024." S&P also notes utilities as having "strained financial cushion."

In addition to S&P, other rating agencies have also commented on the credit quality of regulated utilities. 5 TR 1273. As referenced on page 16 of Mr. Walters' direct testimony, Moody's issued a report in November 2022 in which it revised its outlook on the U.S. regulated utilities sector from stable to negative. *Id.* In addition, on page 17 of his direct testimony, Mr. Walters references a January 2024 report by another credit rating agency, Fitch. In describing a "deteriorating outlook for North American utilities, power & gas in 2024," Fitch cited credit headwinds that are putting pressure on utilities' credit metrics. *Id.* Specifically, Fitch concluded that "the sharp escalation in interest rates has significantly narrowed the headroom in FFO fixed-charge coverage for the sector." It is clear from these reports that rating agencies have recognized a deterioration in credit metrics and credit quality for regulated utilities following what Mr. Walters describes as "periods of declining authorized ROEs." *Id.* These rating agency comments highlight the importance for the Company to maintain strong financial metrics and to not manage toward the perceived low end of the credit metric bands. *Id.*

Mr. Walters performs an assessment of utility capital expenditures, noting that capital expenditures "have increased considerably over the period 2023 into 2024, and the forecasted capital expenditures remain elevated through the end of 2025." 5 TR 3377-3379. A proper equity ratio and ROE keep the cost of capital lower during this period of elevated capital investment. See 5 TR 1273. The Company is making significant capital investments as set forth in this case to maintain and improve infrastructure to the benefit of customers. 5 TR 1274. During this time, the Company will rely heavily on the capital markets to fund these investments. *Id.* Generally, a higher credit rating results in lower financing rates. *Id.* Therefore, it is especially important now for the Company to maintain strong credit ratings. *Id.* The common equity balance and equity ratio projected for the test year in this case also enable the Company to maintain strong credit

ratings and better withstand any shocks in the financial markets. *Id.* Strong credit ratings can help protect customers from spikes in interest rates which increase the cost of capital, and/or inaccessibility to the capital markets which serve as a key source of financing for the Company's capital investments. *Id.*

Mr. Walters states that the Company's projected equity ratio of 50.75% "significantly exceeds the equity ratio for the proxy group used to estimate the cost of equity for Consumers." 5 TR 3394; 5 TR 1274. Mr. Walters then references his Exhibit AB-8 which shows a proxy group average equity ratio of 39.5%. This is also highlighted on page 26 of Mr. Walters' direct testimony. Mr. Walters's average equity ratio reflected on Exhibit AB-8 is not in any way relevant or comparable to the Company's projected equity ratio of 50.75% in this proceeding. 5 TR 1274. It suffers from the same absolute flaw as the Attorney General witness, Mr. Coppola's, Exhibit AG-1.19. *Id.* Like Mr. Coppola's Exhibit AG-1.19, the average equity ratio calculation for the proxy group on Mr. Walters' Exhibit AB-8 uses the equity ratio at the parent holding company level, which may be distorted by other non-regulated balance sheet items and provides a completely inappropriate point of comparison. *Id.*

For example, the equity ratio for DTE Energy listed on Mr. Walters' Exhibit AB-8 is 34.5% which is clearly not based on the Commission's regulatory authorization and is therefore not comparable or relevant in determining the appropriate equity ratio for the Company in this case. 5 TR 1274-1275. Further, it is not clear which peer average Mr. Walters recommends should be used in determining the appropriate equity ratio for the Company in this proceeding. 5 TR 1275. Earlier in his direct testimony, Mr. Walters references average state authorized equity ratios in his Table CCW-2 which reflects an average of 51.59% in 2023. While the average equity ratios in this table are understated as explained above, they are dramatically higher than the 39.5% reflected

on Mr. Walters' Exhibit AB-8 which Mr. Walters then references. For these reasons, Mr. Walters' comparison of the average equity ratios on his Exhibit AB-8 to the Company's projected equity ratio of 50.75% is not comparable or relevant and should be disregarded. *Id.*

Finally, Mr. Walters again compares the Company's projected equity ratio of 50.75% to his average equity ratio calculation of 39.5% as shown on his Exhibit AB-8. 5 TR 1275. Mr. Walters then references an order from the Arkansas Public Service Commission for the Southwestern Electric Power Company in which an imputed average capital structure of companies with comparable risk was used in determining the overall cost of capital. This order does nothing to support Mr. Walters' recommended equity ratio of 50.0%. *Id.* Page 23 of the Arkansas Public Service Commission order referenced by Mr. Walters states that "the Arkansas Court of Appeals has upheld that in instances where the utility's capital structure is unsound or out of sync with industry standards, a regulatory commission may calculate the cost of capital based not on the utility's actual capital structure but on a hypothetical capital structure." On Exhibit A-36 (MRB-10), the Company has shown that the average equity ratio for the Company's peer group is 53.32%. 5 TR 1275-1276. Based on this evidence, the only way in which the Company's equity ratio is "unsound or out of sync with industry standards" is that <u>it is too low</u>. 5 TR 1276. Regardless, the Company is not aware of any instances in which the Commission has accepted the use of an imputed average capital structure of ROE proxy group parent holding companies in developing the projected test year capital structure in a rate case proceeding. For those two significant reasons, the Arkansas Public Service Commission's order for the Southwestern Electric Power Company referenced by Mr. Walters does not support his recommended equity ratio of 50.0% in this proceeding and should be disregarded. *Id*.

C. Return on Common Equity

1. Introduction

References in the Record: Wehner (as Adopted by Bleckman), 5 TR 1334-1384, Exhibits A-14 (TAW-1), Schedule D-5, A-164 (TAW-2) through A-182 (TAW-20); Bleckman, 5 TR 1276-1331, Exhibits A-213 (MRB-22) through A-226 (MRB-35); Megginson, 5 TR 3560-3569, 3579-3598, Exhibit S-4, Schedules D-1 through D-6; Coppola, 5 TR 2800-2841, Exhibits AG-1.16 through AG-1.29; Walters, 5 TR 3371-3438, Exhibits AB-7 through AB-21; Perry, 5 TR 3448-3461, Exhibits WAL-2 through WAL-5; Bandyk, 5 TR 2943-2972, Exhibits CUB-4 through CUB-11; Cira-Reyes, 5 TR 3498-3499, 3516-3518

Consumers Energy's ROE is one of the most important factors in the eyes of current and potential investors, lenders, and rating agencies, in evaluating whether the Company is an attractive investment, whether the Company should be given access to capital, and on what terms the Company should obtain access to capital. In other words, ROE is one of the most important factors for evaluating the Company's financial strength – its credit. The Company's electric service requires significant capital, and thus good credit, for both planned and unplanned investments. The Company's ROE is crucial to its ability to provide its customers with reliable energy supply, customer service, and affordable rates. 5 TR 1339-1341. This ability takes significant financial planning that starts with an ROE that assures that investors deem the Company an attractive investment and allows the Company to maintain a credit rating to obtain access to capital at reasonable terms which, in turn, saves customers money.

Throughout his testimony in this proceeding, the Company's witness, Mr. Bleckman[12], has shown that Staff, the Attorney General, ABATE, and other intervenors promote risky financial approaches in repeated efforts to reduce the Company's ROE (and equity ratio). These efforts are misguided. As the Commission recognized in Case No. U-18322, "customers do not benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a

[12] Mr. Bleckman adopted testimony that was originally filed by Todd A. Wehner.

timely manner." MPSC Case No. U-18322, February 28, 2018 Order ("U-18322 Order"), page 43. The words "accessing capital at attractive terms and in a timely manner" are profundity. They tie directly to the U.S. Supreme Court's statement in its *Bluefield* decision that a utility's returns should be proper "to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties" 262 U.S. 693. For a public utility like the Company, the purpose of good credit is therefore to provide access to capital at attractive terms and at the right time in order to benefit customers by providing a commensurate quality to the provision of its public service.

Mr. Bleckman acknowledged that, as a general rule, the Company, in planning its requested ROE in a rate case, cannot rely entirely on current or temporary market conditions, and, instead, it has to plan for the possibility of unforeseen market events that may impact the Company's borrowing and other operations. 5 TR 1340. In other words, Mr. Bleckman recognized that the Company must minimize financial risk through proper planning. He noted that recent global market disruptions due to the Israeli Middle East conflict, the U.S. banking crisis, the Russian-Ukraine conflict, and COVID-19 pandemic are but demonstrative of unforeseen events that can meaningfully impact economic volatility. 5 TR 1340. He explained that customers would not be well served if the Company is not able to maintain reasonable financial cushion to downgrade thresholds. *Id*. The impact of unforeseen events, that can and do happen, coupled with an inadequate financial cushion, could cause delays in planned work on major infrastructure projects that are geared toward maintaining or improving service to customers and secure reliable energy supply at affordable rates. 5 TR 1341. It is paramount that the Company must therefore prepare for unforeseen events and assure that it remains financially strong in the face of those events as

they arise. 5 TR 1340. In sum, good credit minimizes what is otherwise substantial risk to the Company and its customers.

Mr. Bleckman's testimony described ROE as a measure of how much return a company is able to generate with each dollar of shareholder equity (investment) it receives and explained that investors compare the ROE of similar companies to help them decide which ones constitute the most attractive investment choices. 5 TR 1341. Therefore, the ROE of the Company should not be seen in a vacuum, or even between just the Company and its customers, but can only be validly viewed with the addition of a comparison with other companies. As stated above, ROE is a significant part of a company's overall rate of return, which is the amount of return a utility earns, over and above its expenses. *Id*. It is therefore very important consistent with the holding in *Bluefield*.

Mr. Bleckman also testified that having a reasonable ROE is important because it, in part, contributes to delivering consistent financial performance, and consistent financial performance is attractive to investors and prompts new or continued investment in the Company. 5 TR 1344. He explained that the investment provided by utility shareholder, and the return allowed on that equity, provide the financial resources and capital to (i) support the debt financing raised by the utility, (ii) procure contracts with suppliers, and (iii) fund unplanned or unexpected expenses. *Id*. Thus, a reasonable ROE not only contributes to better credit for borrowing costs and terms, but it also generally attracts increased investment interest in the Company and the State. *Id*. Of course, lower borrowing costs and increased investments in the Company both benefit the Company's customers and supports the mandate for reasonable returns under the Fourteenth Amendment.

As part of the Company's financial planning, the Company is also mindful of its customers and assuring that the costs associated with the Company's ROE recommendation do not, at the

same time, place an undue hardship on customers. 5 TR 1342. The Company continuously recognizes the need to balance customer and investor interests. *Id*. Mr. Bleckman acknowledged that while it is important for an ROE to attract cost-efficient capital discussed above, it is also important to remember, as he noted, that the Company's ROE is not the primary driver of customer bills or total costs and therefore the recommended ROE of 10.25% would have a minimal[13] gross impact on the average monthly residential customer bill. 5 TR 1255-1256. Mr. Bleckman emphasized impact on a "gross" basis because this ROE impact may be partially offset by lower debt costs and improved access to capital markets. *Id*.

The U.S. Supreme Court has 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 *Bluefield* and *Hope* 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.

Taking all of these elements into consideration, Mr. Bleckman presented multiple analyses and arguments supporting a reasonable ROE range of 10% to 11%. 5 TR 1183; see Exhibit A-14

[13] Incremental cost to the average monthly bill from 9.9% ROE to 10.25% ROE would impact the average bill by less than 1%.

(TAW-1), Schedule D-5, page 11. 5 TR 1182. Additionally, and as described below, in this case the witnesses who argue for a lower ROE present analyses that actually support the Company's proposed ROE at 10.25%. The record in this case contains voluminous testimony regarding the appropriate ROE and equity ratio for the Company, and the entirety of the Company's testimony and rebuttal testimony, along with the underlying analysis of much of the parties' testimony, supports Mr. Bleckman's recommended ROE.

Despite the overwhelming evidence, including their own, Staff, the Attorney General, ABATE, MNSC, and Walmart witnesses are all recommending a reduction in the Company's authorized ROE ranging from 5 basis points to a whopping 61 basis points while simultaneously lowering the Company's authorized equity ratio. 5 TR 1277. None of these recommendations are even remotely reasonable or appropriate based on the analysis presented by these witnesses in this case, and certainly as compared with the Company's last electric rate case. *Id.* If adopted by the Commission, the recommendations, especially given the trend, represent a significant change in the Company's ROE.

As the Commission Order in Case No. U-18322 explained, however, "it is not realistic to make a significant change in ROE ***absent a radical change in the underlying economic conditions***." U-18322 Order, page 44 (emphasis added). The intervenors in this case all agree in requesting a change to the Company's authorized ROE that is meaningfully lower, but none have shown a radical change in conditions. However, as Mr. Bleckman observed, conversely, the analyses lead to the conclusion that there should be an increase to the authorized ROE. 5 TR 1339. Credit analysts and investors do not consider utilities to be 'safe havens' anymore, especially during times of elevated interest rates (when the cost of equity is high). 5 TR 1345, 1355-1356. In fact, Mr. Bleckman points out that the Company's requested ROE would only slow rating

agencies and investors' concerns regarding the Company's financial health. 5 TR 1352. The Staff and Intervenor ROE recommendations are not adequate to ensure the financial soundness of the business and are not sufficient to maintain credit and attract capital. As such, the proposed ROEs promoted by Staff, the Attorney General, ABATE, MNSC, and Walmart should be rejected, and the Company's proposed ROE and equity ratio should be authorized.

2. <u>The Financial Health of Consumers Energy is Important and the Company's Authorized ROE Impacts that Financial Health and Provides the Opportunity for Financial Soundness of the Business and a Sufficient Return to Maintain Credit and Attract Sufficient Capital When Needed Under Reasonable Terms</u>

References in the Record: Bleckman, 5 TR 1192, 1277-1278, 1281-1282, 1326, 1358-1359

Two of the elements discussed in the *Bluefield* and *Hope* cases, adequate return to ensure the financial soundness of the business, and sufficient return to maintain credit and attract capital, are intertwined. In order to serve its customers, significant capital for both planned and unplanned investments in property, plant, and equipment is required. As Mr. Bleckman stated in his rebuttal testimony, the Company will need to continue to raise capital in order to deliver its Reliability Roadmap and comply with Michigan's new energy law and doing both on behalf of its customers. 5 TR 1281. Access to capital markets can and will deteriorate if the Company does not maintain strong and disciplined financial metrics. *Id.* Some parties have advocated for continued material weakening of the Company's financial strength for several years in successive cases. *Id.* If the Commission declines to concede to the position of the other parties in this case and approves the Company's request for a modest increase in its ROE (and equity ratio), it will at least slow if not end the continued credit deterioration and send a strong and supportive signal to markets and investors that would allow the Company to further attract and allocate capital to Michigan. 5 TR 1192, 1281-1282.

The Intervenor Parties appear to regard reduction in the Company's ROE and equity ratio as a simple means to try and extract some small, short-term, customer saving. But, this view is wrong and risky. The Company must be financially healthy and must maintain a credit rating that will allow it ready access to capital on reasonable terms. The Commission recognized the importance of the Company's ROE in Case No. U-18322 (Consumers Energy's 2017 Electric Rate Case), where the Commission noted that a lower ROE is not always in the best interest of customers. 5 TR 1277-1278. The Commission specifically stated that its ROE authorization in that case "reinforces the Commission's belief that customers do not benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner." U-18322 Order, page 43. That reasoning continues to apply in this case.

Further, when the parties suggest that the Company is on a solid financial footing and subject to a supportive regulatory environment, they fail to recognize that credit analysis is done prospectively – predicated on expected future outcomes. 5 TR 1326. The Company did enjoy a track record of reasonable regulation through 2020 that supported the credit, financial health and strength of the utility. However, as Mr. Bleckman noted in his adopted direct testimony, there was a decline in the Company's credit metrics following the period of stability that led to the Company's 2021 credit downgrade. 5 TR 1351. Credit analysists have noticed the concerning trend in Michigan. 5 TR 1350-1351. The aforementioned parties also fail to recognize that when attempting to attract capital, the Company is competing with other utilities that may not have had the same instability and declines in credit metrics. 5 TR 1358-1359. Thus, adopting the recommendations of the other witnesses to further lower the ROE and equity ratio should give the Commission concern, given the negative impacts of the numerous identified pressures affecting

the market and the Commission's goal of maintaining a financially sound utility for the benefit of customers. 5 TR 1282.

Three primary and interconnected drivers contribute to the financial strength of a utility, such as Consumers Energy – the Company's credit rating, investor expectations, and the supportiveness of the regulatory environment.

a. <u>The Company's Proposed ROE is Important to Credit Agencies, which in turn Guide Investors' Decisions of Where and When to Deploy Capital</u>

References in the Record: Bleckman, 5TR 1185, 1191-1194, 1238, 1267, 1274, 1281-1284, 1339-1340, 1344, 1349, 1361, Exhibits A-36 (MRB-12); A-37 (MRB-13); and A-38 (MRB-14); Megginson, 5 TR 3562; Coppola, 5 TR 2827; Walters, 5 TR 3382

As Mr. Bleckman explained, the ROE authorized by the Commission and the ability of the Company to earn a fair return are important to credit rating agencies. In fact, a utility's authorized ROE and a consistent, constructive track record in this regard are key components in credit ratings assessments, likewise for investors. 5 TR 1344, 1349, 1361. Because access to capital (i.e. borrowing and financing) by the Company is tied to the state of capital markets, the Company must financially plan to avoid subjecting its borrowing and financing to the uncertainty of the current state of the capital markets – for both access to those markets and the terms of financing (i.e. interest or borrowing rates). 5 TR 1193, 1238, 1267, 1274, 1281-1282, 1339. This is important because a higher credit rating ensures that the Company is able to obtain financing at lower interest rates.

The financial strength of a utility and credit quality can be compromised if financial planning to maintain sufficiency of rates and returns are not recognized and maintained. Compromises often result from unforeseen events ranging from legislation (i.e. the Tax Cuts and Jobs Act of 2017), to global events (e.g. the COVID-19 pandemic and Ukraine/Russia conflict). As Mr. Bleckman discussed in his rebuttal testimony, since 2020 alone there have been global

market disruptions arising out the COVID-19 pandemic, the Ukraine/Russia conflict, the recent banking crisis, and the Israeli Middle East conflict. 5 TR 1282. Further, high levels of inflation caused the Federal Reserve into an interest rate hiking cycle have caused uncertainty. 5 TR 1359. To avoid risk to the Company and its customers, in planning for these types of unforeseen events that affect market conditions, the Company is taking steps to assure that it remains financially strong in the face of those events as they arise. 5 TR 1340.

As set forth in the testimony and exhibits of the Company's witnesses, the Company is making significant capital investments to maintain and improve infrastructure to the benefit of customers. During this time, the Company will rely heavily on the capital markets to fund these investments. 5 TR 1193-1194. Generally, a higher credit rating results in lower financing rates; therefore, it will be especially important for the Company to maintain strong credit ratings over this period. 5 TR 1191. The ROEs recommended by the other parties in this case suggest that the Company should manage to the margins. As Mr. Bleckman's testimony described, however, doing so would make the Company particularly susceptible to impacts from market conditions, including those that are unforeseen. 5 TR 1185. Such impacts could cause adjustments or delays in planned work on major infrastructure projects that are geared toward maintaining or improving customer service and secure and reliable energy supply at affordable rates. *Id.*

In recent years, rating agencies have been expressing concern over the Company's credit metrics due, in part to the reductions in ROE authorized in rate cases. Exhibit A-36 (MRB-12); Exhibit A-37 (MRB-13); and Exhibit A-38 (MRB-14). In this current economy, a reduced ROE has the potential to cascade into challenges in accessing capital, accessing capital at reasonable rates, forward progress on projects that are geared toward maintaining and/or improving customer service, and the ability of the Company to provide secure and reliable energy supply at affordable

rates – all of which are hallmarks of Consumers Energy's business – that customers have come to expect.

A reduced ROE under present circumstances would produce results contrary to the U.S. Supreme Court's requirement from the *Bluefield* decision that the Company must be entitled to an adequate return to ensure the financial soundness of the business to maintain credit and attract capital. A reduced ROE would thus be unjust and unreasonable.

While Staff witness Megginson, Attorney General witness Coppola, ABATE witness Walters, and MNSC witness Matthew J. Bandyk express doubt over the Company's concerns and warnings related to the nexus between ROE and financial strength of the Company, it is worth noting that in 2019, Staff witness Ufolla, in partial support of a proposed ROE of 9.65% in Case No. U-20322, cited "no earthshattering economic changes," saying "nor are any foreseen," for this recommendation. See direct testimony of Staff witness Ufolla, MPSC Case No. U-20322, page 15; 2 TR 1386. This was prior to COVID-19, the Ukraine/Russia conflict, the banking crisis, unprecedented interest rate hikes by the Federal Reserve, increasing inflation, prior to the conflict between Isreal and other Middle East countries, and prior to Moody's downgrade of Consumers Energy's credit rating. The Commission, in its U-20322 Order, a little less than six months before the onset of the COVID-19 pandemic (the first of the major, unprecedented economic events that have occurred between March 2020 and now), said, in part, that "Consumers did not show, by a preponderance of the evidence, that economic and market conditions . . . have significantly impacted the company's cash flow or its credit rating . . . ." At that time, prior to the string of economic events and credit downgrade, the Commission still determined that an ROE of 9.90% was the appropriate ROE, and that the ROEs proposed by Staff (9.65%), the Attorney General (9.5%), and ABATE (9.22%) to be "too low" to have "continued access to capital and the ability

to maintain its sold credit rating." Under the economic conditions at that time (2019), the Commission said that a 9.90% ROE (with an overall rate of return of 5.84%) "will best achieve the goals of providing appropriate compensation for risk, ensuring the financial soundness of the business, and maintaining a strong ability to attract capital." See U-20322 Order, pages 71-72. Again, this is all before the dramatic economic and market impacts and it was prior to the May 10, 2021 Moody's Credit Opinion that downgraded the Company's credit rating. See Exhibit A-36 (MRB-12). While no party could have foreseen a global pandemic, or any of the other added disruptions that have caused severe strains on financial markets, as Mr. Bleckman explained in his rebuttal testimony, "it is precisely because the unforeseen can happen, and does occur, that utilities should be managed conservatively" and further "demonstrates the importance of not managing a company toward the margins." 5 TR 1282, 1284. The rational in the U-20322 Order, applied after the economic and market impacts, and credit downgrade, supports the Company's modest increase in its authorized ROE.

Staff, the Attorney General, and ABATE, while only providing flawed or otherwise insubstantial evidence of their respective ROE recommendations, underrate and generally trivialize all credit risk of the Company – even those expressly stated by credit rating agencies. Although the Company received a downgrade in credit along with this warning, Staff witness Megginson, in his direct testimony, refers to the recent Moody's downgrade merely as a "one notch downward revision" and says that "[d]espite the downward revision . . . the Company should not have a problem accessing the capital markets for reasonably, if not preferably, priced borrowings in the future." Megginson, 5 TR 3562. Similarly, Attorney General witness Coppola simply presents an exhibit (Exhibit AG-1.22), and very generally says that it "shows several electric utilities that have accessed the capital markets at competitive interest rates since receiving a ROE

near or below the average rate of 9.60%." Coppola, 5 TR 2827. He does not speak to the noticeable increase in interest rates between 2021 to 2023, as demonstrated on that exhibit, and how those increases have actually affected the utilities – instead, he just assumes that there has been no affect. There is also no information provided regarding credit rating changes for those utilities in Mr. Coppola's exhibit or testimony. Finally, while ABATE witness Walters recognizes that "the economic outlook is uncertain" (Walters, 5 TR 3382 (internal citation omitted)) and advocates for a lower ROE, he fails to explain why his proposed ROE reduction is more advantageous than a higher ROE with resulting credit stability and lower borrowing costs. Without that, his conclusions, like those of Mr. Megginson and Mr. Coppola, are without any basis, and amount to guesses.

Significantly, Staff, the Attorney General, and ABATE witnesses are asking the Commission to trust their opinions over the published report by a credit ratings agency, but, as Company witness Todd A. Wehner, noted at the time, it was these same voices that provided the same opinions in Case No. U-20697. They all proved to be wrong. As Mr. Bleckman explained, "waiting until problems arise, another downgrade occurs, or capital is difficult to source, to take supportive action is simply not representative of prudent management of an essential service." 5 TR 1284. Bleckman, 5 TR 1284. As a result, the ROE proposals by Staff, the Attorney General, and ABATE (along with Walmart, MNSC, and CEO) should be deemed insufficient to protect the Company's credit rating, particularly in light of recent market and financial impacts, which have clearly been "earthshattering economic changes," and that the Company's proposed ROE should be approved.

b. The Company's Proposed ROE is Important to Investors' Expectations

References in the Record: Bleckman, 5 TR 1341, 1344, 1358, 1361

Access to capital comes from investors. The equity provided by utility shareowners, and the return allowed on that equity, provide the financial resources and capital to: (i) support the debt financing raised by the utility; (ii) procure contracts with suppliers; and (iii) fund unplanned or unexpected expenses. 5 TR 1344. This is vital to the operation of the Company's business. With the infrastructure improvement investment planned by the Company, attracting investment is also crucial. To attract and retain investment from shareowners, an ROE must be commensurate with investments of comparable risk. This fact was recognized by the U.S. Supreme Court when it established that equity investors in a public utility, such as Consumers Energy, are entitled to a return on their investment commensurate with investments of comparable risk. In other words, the Supreme Court acknowledged the relationship between investors' expectations and a utility's access to capital.

Because ROE is a measure of how much return the Company is able to generate with each dollar of shareholder equity (investment) it receives, investors compare the ROE of similar companies to help them decide which ones are the most attractive investment choices. 5 TR 1341, 1358, 1361. Like rating agencies, investors consider the ROE authorized by the Commission, and the ability of the Company to earn the authorized return, important factors in investment decisions. Thus, if the Company's authorized ROE continues to experience reductions, investors may choose to put their money into other investments, rather than the Company, which would deprive the Company of the much-needed financial resources to properly run its business. Again, this would produce results contrary to the U.S. Supreme Court's ruling that the Company is entitled to an adequate return to ensure the financial soundness of the business, and that the Company is entitled

to a sufficient return to maintain credit and attract capital; thus making a reduction in the Company's ROE unjust and unreasonable.

c. <u>The Company's Proposed ROE is Important for Credit Agencies' and Investors' Perception of Michigan's Regulatory Environment and Corresponding Decisions to Invest Capital in Michigan's Infrastructure</u>

References in the Record: Bleckman, 5 TR 1233, 1279, 1292, 1348, 1350, 1341, 1358, 1360-1361, 1363, Exhibits A-164 (TAW-2), A-165 (TAW-3), A-166 (TAW-4)

The Company's five-year plan includes investment of approximately $17 billion on a total Company basis, $11.1 billion of which is earmarked for electric infrastructure investment. This level of capital investment increases the risk profile of the Company for investors and the rating agencies. 5 TR 1360. In addition to concerns that investors will use declining authorized ROEs as an incentive to redirect investments within the state of Michigan, there is also the perhaps more important concern that declining authorized ROEs will incentivize investors to cease investing in Michigan utilities, such as Consumers Energy, and seek out and invest dollars into utilities and businesses outside of the state of Michigan. Investors' decisions will largely depend on how Michigan's regulatory environment is viewed. The ROE proposed by the Company in this case would send an important signal to investors that they are not investing in a company or state that has a declining regulatory environment. 5 TR 1279, 1292, 1363.

Although investors generally view the present overall regulatory environment as supportive, investors have expressed concerns regarding authorized ROEs and a perceived deterioration in Michigan's regulatory environment in recent years. 5 TR 1233. For example, Mr. Bleckman sponsored Exhibit A-164 (TAW-2), a November 21, 2022 publication of The

Fleishman Daily from Wolf Research[14] which observed the following in response to DTE Electric's rate case (Case No. U-20836), and the Company's electric rate case (Case No. U-20963) as follows:

> The revenue requirement and rate base portion of the order looks very light, as it was well below what Staff/ALJ had even recommended, which is disappointing . . . . This reminds us of CMS' electric rate order a year ago, which had an equally tepid rate hike . . . . *Michigan has a history of constructive regulation, but this is now 2 disappointing orders in the last 12 months, which is a little bothersome*… [Exhibit A-164 (TAW-2), page 3, Wolfe Research, November 21, 2022 (emphasis added).]

Mr. Bleckman's testimony reflects that Mr. Fleishman is one of the most experienced, knowledgeable, and respected utility sector analysts, but said that he is not alone in his sentiment on ROE and risk in the state. 5 TR 1350.

Wells Fargo and UBS similarly commented on the recent Michigan electric rate case outcomes. See Exhibit A-165 (TAW-3), page 1, and Exhibit A-166 (TAW-4), page 1. In the November 21, 2022 Equity Research report, Wells Fargo said that rate case outcomes in Michigan presented "a trend worth watching, as MI has long been considered one of the more constructive regulatory environments in the U.S." Exhibit A-165 (TAW-3), page 1. The report went on to say "[t]op of mind for investors right now is whether state regulators will continue to be supportive of utilities' aggressive capital investment programs (designed to support reliability, decarbonization, and electrification efforts) in the face of mounting macroeconomic pressures (inflation, higher interest rates, potential recession, etc.)." Exhibit A-165 (TAW-3), page 1. Then the report, in bold, stated, "[i]n our view, the last two electric rate cases in MI raise the concern that the MPSC is more aggressively hunting for ways to lower customer bills, as opposed to the perceived

[14] Wolfe Research is a research firm which closely monitors the industry and reports on associated topics and how they impact their perceived corporate risk and return market positions. Investors subscribe to the Wolfe Research platform in order to gain access to their opinions and content produced. Wehner, 5 TR 1350.

balanced approach that defined the Commission's regulatory outcomes over the last decade." Exhibit A-165 (TAW-3), pages 1-2 (emphasis added).

This is very worrisome to the Company but also for investment in the state of Michigan. As Mr. Bleckman acknowledged through his adopted testimony, if the investor view of the Michigan regulatory environment becomes less certain or less predictable, then they will be less inclined to invest further capital into Michigan utilities. 5 TR 1348.

If investors view Michigan's regulatory environment as unsupportive and re-direct investment out of state, it will not only potentially impair infrastructure projects (in Michigan) that are planned to maintain and/or improve customer service, and the corresponding ability of the Company to provide secure and reliable energy supply at affordable rates, it would also lead to higher funding costs which would be detrimental to customers. 5 TR 1348. An ROE that causes investors to choose other investments based on a reduced return is contrary to the U.S. Supreme Court's pronouncement in *Bluefield* that equity investors in a public utility, such as Consumers Energy, are entitled to an ROE investment commensurate with investments of comparable risk. It is also contrary to the Court's ruling that the Company is entitled to an adequate return to ensure the financial soundness of the business, and that the Company is entitled to a sufficient return to maintain credit and attract capital; thus, making a reduced ROE unjust and unreasonable.

d. Staff, the Attorney General, and ABATE Offer Inadequate Analyses of Credit Ratings and Investor Expectations that Should Not be Accepted by the Commission

References in the Record: Bleckman, 5 TR 1227-1228, 1231-1233; 1272-1273, 1284-1286, Exhibit A-39 (MRB-13); Megginson, 5 TR 2564; Coppola, 5 TR 2788, 2791, 2803, Exhibit AG-1.25; Walters, 5 TR 3377

Staff

Starting with Staff, Mr. Megginson does not properly acknowledge any of the market forces currently at play, including the perception of the current regulatory environment.

Bleckman, 5 TR 1233. This is problematic because the high interest rate environment and geopolitical issues seen in the market today increase risk for the Company, yet Mr. Megginson is proposing a decrease in equity return for investors despite the increased investment risk. This would not put the Company in fair competition with other similarly situated utilities when seeking investment capital. Further, a simple average of the results of Mr. Megginson's analyses demonstrates that the average result of his methodologies results in an ROE equal to 9.93%, an increase over the average of his results in the Company's last electric rate case (Case No. U-21389) of 24 basis points, yet he goes on to recommend a decrease in the Company's ROE in this case. Further, Mr. Bleckman showed by simply excluding the 2021 and 2022 authorized ROE data that does not fit with current circumstances, **the average ROE using Mr. Megginson's own analyses is 10.04%**. Mr. Megginson notes various issues in the economy, but he proceeded to perform similar analysis as he has in prior cases, as though market influencing events have not happened at all and that high interest rates are gone. Bleckman, 5 TR 1284. Thus, without any substantive quantitative or qualitative analysis of the credit implications of the market forces in his recommended ROE, he goes on to again ignore[15] the Company's most recent credit downgrade and merely presumes, without basis, that, because of the Federal Reserve's actions, "borrowing costs will likely lower and the Company's access to those borrowings should not diminish during the test year." Megginson, 5 TR 3564. He takes this position even though he is simultaneously recommending to further reduce the equity ratio and significantly cut the authorized ROE. This presumption, notably, is contrary to objective evidence presented in this case, including, but not limited to:

[15] Beyond ignoring its impact, Mr. Megginson minimizes the importance of a credit downgrade when he states that it "put the Company's credit rating more in line with the other two agencies ratings." Mr. Megginson also concludes that "the prior Moody's rating appeared to be an outlier" as if a lower rating consensus among the agencies is preferable to a higher rating from any of them – Moody's in this case.

- Moody's reference to lower ROE and equity ratios as a factor in the Company's credit downgrade in 2021 (Bleckman, 5 TR 1227-1228, 1233);
- Articulated rating agency concerns (Bleckman, 5 TR 1231-1233); and
- Failure of Staff to substantiate the 5 basis point proposed reduction in ROE.

The Attorney General

Similarly, Mr. Coppola does not believe there will be any impact to the Company's credit despite his proposed large proposed downward shift in ROE to 9.8% and 50% equity ratio, and he too seems to recommend that the Company could manage credit metrics such as FFO to Debt down to minimum thresholds without any further repercussions from the ratings agencies. 5 TR 2788, 2791. In fact, while he discusses downgrade thresholds, he fails to acknowledge the specific language from his own exhibit that states in addition to declines below thresholds, "[a] rating downgrade could be considered if there is a material deterioration in the credit supportiveness of the Michigan regulatory environment." (Exhibit AG-1.25 page 4) Thus, there are other factors that credit agencies consider. Further, while Mr. Coppola mentioned the necessity of a fair return to allow a utility to attract capital when discussing the general principles of determining the cost of equity for a company, he provides no persuasive supporting evidence to show that Consumers Energy will be able to attract the significant capital it needs to invest in system upgrades with his recommended ROE. 5 TR 2803.

Regardless of the data and analytic models' results, which will be described below, the Attorney General continues to recommend that the Commission adopt low financial metrics for the Company. 5 TR 1285. The Attorney General has not demonstrated an awareness that changing economic and financial challenges can arise that require managing for conditions that may not always be constructive. 5 TR 1285. Mr. Coppola has repeatedly recommended reducing the level

of cash maintained by the Company. 5 TR 1285. For example, in Case No. U-20322 Mr. Coppola recommended the Company maintain less cash:

> The Company has multiple bank lines of credit and **access to the commercial paper market.** These sources of short term borrowing can be accessed when the Company needs funds to meet short term working capital requirements. [Direct testimony of Attorney General witness Coppola, MPSC Case No. U-20322, page 55 (emphasis added).]

Fortunately, the Commission rejected this argument from Mr. Coppola. 5 TR 1285. If the Company ran its business at the margin as Mr. Coppola recommends, it would harm the Company's customers in the event an unforeseen economic or financial event occurs. 5 TR 1285. Mr. Bleckman pointed to the onset of the global pandemic when commercial paper markets and bank markets were distressed. 5 TR 1285. The commercial paper market shut down initially, and when it returned, it did so at highly elevated rates. 5 TR 1285. In March 2023, the commercial paper market again saw disruptions, as some borrowers were not able to refinance their positions and were forced to rely on their revolving credit facilities. 5 TR 1285. Mr. Bleckman correctly cautions that failing to plan and build a reserve for these types of events and instead managing to the margins can have devastating financial effects on a utility (which will impact customers). 5 TR 1285.

Fast forward to this case, Mr. Coppola's recommendations combined with his continued position that the Company should maintain lower cash balances, seem to express a view that utilities should maintain much lower financial metrics, take on more financing risk, and that doing so would benefit customers. 5 TR 1285-1286. This is misguided and risky for not only the Company, but for its customers, and at best it is shortsighted. The Commission should reject Mr. Coppola's position and instead continue to support financially strong utilities over the long

term. Mr. Bleckman shared an S&P statement that recently warned about this erosion in its published report:

> About 35% of the industry is sustaining performance with minimal financial cushion, reflecting funds from operations (FFO) to debt that is less than 100 basis points (bps) above their downgrade threshold. **The limited financial cushion affects a company's ability to absorb unexpected events beyond the base case for our ratings, increasing its susceptibility to a downgrade.** Such unexpected events include higher interest rates, changes to inflation, delays to offshore wind projects, and rising taxes. [S&P, February 14, 2024, Exhibit A-39 (MRB-13) (emphasis added).] 5 TR 1286.

ABATE

ABATE witness Walters misunderstands the trends when it comes to credit ratings agencies' expectations. Mr. Walters shows S&P ratings data from 2009 to 2024 in an attempt to show that regulated utility companies have been able to maintain relatively strong credit ratings during periods of declining authorized ROEs. Bleckman, 5 TR 1272; Walters, 5 TR 3377. However, in a February 2024 report, highlighted on page 15 of Mr. Walters' direct testimony, S&P updated their outlook of the regulated utility industry to negative. Bleckman, 5 TR 1272. S&P cited the high percentage of utilities with negative credit outlooks and stated its expectation that 2024 will likely be the fifth consecutive year that credit downgrades outpace upgrades. 5 TR 1272. S&P cited "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus equity. Exhibit A-39 (MRB-13). S&P further stated that "for 2023, the industry's actual equity issuance was considerably below our expectations, resulting in a weakening of financial performance and credit quality. If this trend persists, credit quality will again likely experience pressure in 2024." 5 TR 1272-1273. S&P also noted utilities as having "strained financial cushion." To the contrary of the picture Mr. Walter's paints, the credit agencies are concerned with the trends.

Likewise Moody's, which is referenced on page 16 of Mr. Walters' direct testimony, issued a report in November 2022 wherein it revised its outlook on the U.S. regulated utilities sector from stable to negative. Bleckman, 5 TR 1273. On page 17 of his direct testimony, Mr. Walters then references a January 2024 report by another credit rating agency, Fitch. In describing a "deteriorating outlook for North American utilities, power & gas in 2024," Fitch cited credit headwinds that are putting pressure on utilities' credit metrics. *Id.* Specifically, Fitch concluded that "the sharp escalation in interest rates has significantly narrowed the headroom in FFO fixed charge coverage for the sector." *Id.* Rating agencies have recognized a deterioration in credit metrics and credit quality for regulated utilities following what Mr. Walters describes as "periods of declining authorized ROEs." Bleckman, 5 TR 1273; Walters, 5 TR 3377. Despite the arguments that Mr. Walters attempts to make, these rating agency comments highlight the negative trends that the industry faces, thus also highlight the importance of the Company maintaining strong financial metrics and not manage toward the perceived low end of the credit metric bands. Bleckman, 5 TR 1273.

Staff, the Attorney General, and ABATE have failed to demonstrate or discuss how a reduction in the Company's authorized ROE will provide adequate return to ensure the financial soundness of the business and assure that a sufficient return to maintain credit and attract capital. As such, they have failed to substantiate a reduction in the Company's proposed ROE, particularly in light of impacts arising out the COVID-19 pandemic, the Ukraine/Russia conflict, increased interest rates by the Federal Reserve, inflation, the Israeli Middle East conflict, and credit downgrade, and the Company's proposed ROE of 10.25% should be authorized by the Commission.

3. The Company's Quantitative Analysis Thoroughly Supports an ROE of 10.25%

References in the Record: Bleckman, 5 TR 1346, 1363-1384, Exhibit A-14 (TAW-1), Schedule D-5

In order to follow the principles reflected in *Hope* and *Bluefield* for setting a fair rate of return, Mr. Bleckman performed a quantitative analysis to estimate ROE using several methodologies. This included the use of several quantitative models to determine a return for investments having commensurate risk. 5 TR 1346. Further, because determining an ROE for an investment of commensurate risk is not an exact science, and any methodology utilized is based on assumptions and inputs that likewise may be less than certain, Mr. Bleckman applied his qualitative judgement to the multiple methodologies. Individually, each of these methods will often produce a range of values, but in sum, they present a good overall picture of investments having commensurate risk. See *Id.*; see also Exhibit A-14 (TAW-1), Schedule D-5, page 11. Additionally, results of these quantitative models often make assumptions that do not necessarily fully reflect the returns that investors actually require, given current economic and financial conditions; therefore, Mr. Bleckman also specifically considered in his analyses numerous market forces as discussed earlier that have adversely impacted investor risk tolerance when it comes to their consideration of where to invest – the Company or elsewhere.

Mr. Bleckman performed quantitative analyses that started with the selection of a proxy group. Wehner, 5 TR 1363; Exhibit A-14 (TAW-1), Schedule D-5, page 1. He then utilized multiple methodologies to determine a range of appropriate ROEs, including the Capital Asset Pricing Model ("CAPM"), Empirical Capital Asset Pricing Model ("ECAPM"), Projected Risk Premium, Discounted Cash Flow ("DCF"), and Comparable Earnings Analyses. 5 TR 1363-1384. Ultimately, Mr. Bleckman applied multiple methods, in combination with an overall qualitative

assessment using his judgement and knowledge of the current marketplace, in order to provide a more comprehensive evaluation of cost of capital and which is most appropriate in evaluating the required cost rate for common equity capital. 5 TR 1366.

a. The Company's Proxy Group Consists of Companies of Like Risk and is the Most Appropriate for the Comparison Necessary to Establish the Company's ROE

References in the Record: Bleckman, 5 TR 1363-1365, Exhibit A-14 (TAW-1), Schedule D-5

Since the common stock of Consumers Energy is not publicly traded, it is necessary to use indirect or proxy approaches for purposes of comparison to calculate an appropriate representative ROE. 5 TR 1363. In order to determine utilities comparable to the Company that are of like risk, consistent with the *Bluefield* and *Hope* decisions, Mr. Bleckman elected publicly traded companies using criteria set forth in his adopted testimony. See 5 TR 1364.

The application of these criteria resulted in a proxy group of 12 companies, the same Company proxy group from Case No. U-21389 along with FirstEnergy, OGE Energy, Pinnacle West Capital, and PPL. The list of the proxy group companies, the selection criteria, and the data supporting inclusion is set forth on Exhibit A-14 (TAW-1), Schedule D-5, page 1. 5 TR 1365.

b. Application of Quantitative Models Demonstrates an Appropriate ROE of Between 10% and 11%

References in the Record: Wehner (as adopted by Bleckman), 5 TR 1347, 1365-1377

After selecting a proxy group that represents and has characteristics most closely aligned with the Company, Mr. Bleckman then utilized multiple methodologies to determine a range of appropriate ROEs, including the CAPM, ECAPM, a Projected Risk Premium analysis, a Comparable Earnings Analysis, and a DCF analysis. Mr. Bleckman assessed the ROE for Consumers Energy's electric operations using these methodologies in combination with

assessments of the market and risk environment for Consumers Energy. See, generally, 5 TR 1365-1384 Those analyses had the following results:

Summary of ROE Estimates

Capital Asset Pricing Model ("CAPM")	11.74% - 13.85%
Empirical Capital Asset Pricing Model ("ECAPM")	11.96% - 13.70%
Projected Risk Premium	10.24% - 11.20%
Analyst Consensus Discounted Cash Flow ("DCF")	8.35% - 11.02%
Comparable Earnings	9.19% - 15.00%
Recommended Range	**10.0% - 11.0%**

5 TR 1347.

i. CAPM and ECAPM

References in the Record: Wehner (as adopted by Bleckman), 5 TR 1366-1371, Exhibit A-14 (TAW-1), Schedule D-5

The principal assumption of the CAPM and ECAPM is that the expected return on an asset is related to risk – that is, risk taking is rewarded with appropriate returns. 5 TR 1366. ECAPM is derived from CAPM. The CAPM and ECAPM state that an investor's expected rate of return on an investment is equal to a risk-free rate of return plus a risk premium as a form of additional compensation for the investor's additional risk tolerance. 5 TR 1366. The size of the risk premium for an investment is dependent on the amount of the unavoidable (or systematic) risk taken. 5 TR 1366. An investment's systematic risk is obtained by the application of a beta, which is used as an indication of the level of risk of an investment relative to the risk of a market portfolio consisting of all types of risk-oriented assets. 5 TR 1366. Thus, under CAPM theory, there is an incremental premium for bearing additional risk, as measured by beta, above the risk-free rate, which is traditionally seen as the income return available from investing in United States Government

Treasury bonds. Wehner, 5 TR 1367. In this case, the Company performed two separate CAPM analyses – (i) a traditional CAPM analysis, and (ii) an ECAPM analysis.

The CAPM and ECAPM include (i) a 4.53% test year risk-free rate, and (ii) an 8.48% projected equity risk premium. 5 TR 1370-1371; See Exhibit A-14 (TAW-1), Schedule D-5, pages 2-3. Mr. Bleckman utilized the expected 30-year United States Treasury yield of 3.84 as the test year risk free rate estimated by the current interest rate expectation. 5 TR 1370-1371. In order to estimate an appropriate projected risk premium for the projected test year, Mr. Bleckman calculated a market implied equity risk premium of the S&P 500 that is developed in Exhibit A-14 (TAW-1), Schedule D-5, page 10. He estimated the projected, or forward looking, market risk premium ("MRP") by subtracting the expected yield of the 30-year United States Treasuries during the projected test year from the expected market return of the S&P 500 Index. 5 TR 1370. The test year risk-free rate was calculated by utilizing the estimates provided by Bloomberg's Forward Curve derived estimate. 5 TR 1371. The 30-year time horizon does, and should, match the time horizon of whatever is being valued. 5 TR 1371. When valuing a business that is being treated as a going concern, the yield of a long-term, i.e., 30-year Treasury bond is appropriate. 5 TR 1371. The expected market return was calculated as the summation of the dividend yield and the long-term Earnings Per Share ("EPS") growth estimates for the entire index. 5 TR 1370. The estimated market capitalization weighted dividend yield of 1.56% and long-term EPS growth estimate of 11.45% resulted in a sum expected market return of 13.01% as of April 12, 2024. 5 TR 1370. Subtracting the expected 30-year United States Treasury yield of 4.53% for the test period results in an estimated MRP of 8.48% for the test period. 5 TR 1370-1371. Because the test year is in the future, it makes sense that the analyses supporting the Company recommendations rely on

projected market data to estimate returns for the forward-looking period; therefore, projected inputs and assumptions are appropriate. 5 TR 1371.

a) Traditional CAPM

References in the Record: Wehner (as adopted by Bleckman), 5 TR 1368-1369, 1372, Exhibit A-14 (TAW-1), Schedule D-5

The Company first performed a traditional CAPM analysis, which results are set forth in Exhibit A-14 (TAW-1), Schedule D-5, page 2. The Projected Risk Premium CAPM ROEs are displayed in column (g) and show the average ROE for the proxy group is 12.51% and range from a minimum of 11.74% to a maximum of 13.85%. 5 TR 1369 It is worth mentioning that these results are of course higher than the Company's requested ROE of 10.25% and certainly support the directionality of an increase to the Company's currently authorized ROE.

Further, Mr. Bleckman's testimony reflected that CAPM results do not capture all of the risk faced by utility investors; thus, there are a number of shortcomings that suggest the Company's requested ROE is already toward the low end of where it should be. 5 TR 1368. Those shortcomings include that: (i) CAPM tends to overstate the sensitivity of the cost of capital to beta (low beta assets tend to have higher average returns than would be predicted, while high beta assets have lower returns; thus, the beta of utilities would tend to have higher average returns than predicted by the model); and (ii) CAPM relies on beta to capture all of the systemic risk faced by a company and assumes that the only unavoidable (or systemic) risks are fluctuations in the market (market beta calculates a low result for a company with low correlation to the broad market when, in fact, the company could experience high stock volatility that is simply not correlated with the market). 5 TR 1368. Ultimately, while a valuable analytic tool, CAPM analysis underestimates the risk premium for utilities. 5 TR 1372.

b) ECAPM

References in the Record: Wehner (as adopted by Bleckman), 5 TR 1369-1370, Exhibit A-14 (TAW-1), Schedule D-5

To address some of the CAPM shortcomings, Mr. Bleckman's analysis began with the same assumptions as the CAPM which applied long-term risk-free rates and adjusted betas (calculated by Value Line). Exhibit A-14 (TAW-1), Schedule D-5, page 3. However, because these adjustments do not fully address the shortcomings of CAPM, Mr. Bleckman included an alpha adjustment, which is not a component of the traditional CAPM formula but is required for the model to make sense. 5 TR 1369. Specifically, the ECAPM's inclusion of an alpha adjustment to the risk-return line better predicts the relationship between asset returns and risk. 5 TR 1369. Mr. Bleckman applied a 1.5% alpha adjustment to the risk-return line, which is the midpoint in the range of 1% to 2% described as reasonable by Dr. Morin in his book New Regulatory Finance. 5 TR 1369; See Exhibit A-14 (TAW-1), Schedule D-5, page 3, column (e).

The ECAPM results are found on Exhibit A-14 (TAW-1), Schedule D-5, page 3. The ECAPM ROEs are displayed in column (h) and show the average ROE for the proxy group is 12.60% and range from a minimum of 11.96% to a maximum of 13.70%. 5 TR 1370. The Commission may give an ECAPM analysis whatever weight it chooses. In any event, and at a minimum, the results provide support for the Company's requested ROE of 10.25%.

ii. Projected Risk Premium Analysis

References in the Record: Wehner (as adopted by Bleckman), 5 TR 1377-1378, Exhibits A-14 (TAW-1), Schedule D-5, and A-179 (TAW-17)

Mr. Bleckman's testimony next included a Projected Risk Premium Analysis to project ROEs for the Company's proxy group. Investors can choose to invest in either debt or equity in a company. Wehner, 5 TR 1377 Debt (i.e. loaning funds at a defined interest rate) is subject to less risk as it receives a priority claim on assets in bankruptcy relative to equity (i.e. purchasing an

interest in an investment (securities) in return for dividends and potential growth). 5 TR 1377. Further, interest payments, unlike dividends paid on equity, are mandatory and cannot be deferred. 5 TR 1377. Because of the higher risk involved, investors in equity securities, therefore, demand a premium relative to the return paid on the debt. 5 TR 1377-1378.

The risk premium analysis estimates the required rate of ROE by estimating the future yield of utility bonds and then adding the estimated risk premium. 5 TR 1378. To determine the future yield of utility bonds, Mr. Bleckman added: (i) the risk-free rate; and (ii) the bond spread over United States Treasury Bonds. 5 TR 1378. The applied risk-free rate in the Projected Risk Premium Analysis is the projected long-term government bond return of 4.53% discussed earlier. 5 TR 1378. The estimated bond yield was estimated for each of the bond rating spreads from A to BBB by adding the applicable corporate spreads that have been observed in the market. 5 TR 1378. Exhibit A 14 (TAW-1), Schedule D-5, page 8, column (i), shows that electric utility common stocks have an average historical risk premium of 4.37% (line 94) over the yields of A rated utility bonds. This premium was added to the estimated bond yields to arrive at a range of cost of equity estimates. 5 TR 1378.

A Projected Risk Premium analysis is a reasonable methodology. 5 TR 1378. An article published by the Federal Reserve, Exhibit A-179 (TAW-17), page 2, indicates that equity risk premiums in environments with heightened Federal Reserve action are much higher than normal, which renders the application of historical data without additional careful consideration less reliable. 5 TR 1378.

The Projected Risk Premium analysis shows that the average ROE is 10.62% and ranges from a minimum of 10.24% to a maximum of 11.20%. 5 TR 1378; Exhibit A-14 (TAW-1), Schedule D-5, page 4. These results support the Company's requested ROE set at 10.25%.

iii. Discounted Cash Flow Analysis

References in the Record: Wehner (as adopted by Bleckman) , 5 TR 1379-1383, Exhibits A-14 (TAW-1), Schedule D-5, A-180 (TAW-18)

The DCF model is a type of income model. 5 TR 1379. In its simplest form, this model can be used to estimate the required cost of equity capital for a dividend-paying stock with an assumed constant expected growth rate to perpetuity. 5 TR 1379. Mr. Bleckman's application of this model, which was performed using dividend growth estimates from analysts, is found on Exhibit A-14 (TAW-1), Schedule D-5, page 5. It should be stressed that the use of dividend growth is consistent with the fundamental basis of this model. See Exhibit A-180 (TAW-18), and page 5; 5 TR 1382. In fact, the original authors of this model said,

> Translated, this means that the rate of profit at which a share of common stock is selling is equal to the current dividend, divided by the current price (the dividend yield), plus **the rate at which the dividend is expected to grow**. [Exhibit A-180 (TAW-18) (emphasis added).]

The DCF model is based upon an analysis of publicly traded common stock. 5 TR 1379. The DCF theory is based on the premise that an investor who agrees to purchase common stock at a given market price is purchasing the rights to an income stream. 5 TR 1379. That income stream includes the present and anticipated earnings, the portion of those earnings that are currently and prospectively being paid to investors in the form of dividends, and the proceeds of capital appreciation derived from the ultimate sale of the stock at some future market price. 5 TR 1379. Implicit in the investor's decision to buy is the assumption that the investor considers the magnitude of that income stream. 5 TR 1380. This includes the rate at which those dividends are expected to grow and the expected future selling price of the stock. 5 TR 1380. The investor also considers the quality or risk of that income stream; that is, the likelihood that expectations will, in fact, be realized. 5 TR 1380. The model assumes an annual dividend payment and that dividends,

earnings, book value, and price per share grow at the same constant annual rate over time. 5 TR 1380.

Mr. Bleckman's calculation utilized dividend growth[16], consistent with the fundamental basis of the model. Specifically, he calculated the dividend yield for the proxy companies by dividing the expected annual dividend by an average of 30 daily closing stock prices for each company through January 31, 2024. 5 TR 1381. One of the difficult steps in applying the DCF model is determining the appropriate growth rate. 5 TR 1381. 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. 5 TR 1381. Though this is ideal, analysts do not typically provide long-term growth for dividends. 5 TR 1381. Therefore, Mr. Bleckman's testimony utilized analyst projections for dividends over the next three years to estimate dividend growth. 5 TR 1381.

Exhibit A-14 (TAW-1), Schedule D-5, shows the results for the Company's group of proxy companies. Proxy group company returns for the Analyst Consensus DCF ROE have a range from 8.35% to 11.02% with an average return of 9.85%. 5 TR 1382.

Mr. Bleckman testified that the results of the DCF analysis do not fully reflect the cost of equity required for utilities. 5 TR 1382. The DCF is highly reliant upon growth estimates and provides a mechanical application of the DCF that, when taken alone, delivers results that are less reliable and does not produce a risk-appropriate ROE, as required by *Hope* and *Bluefield*. 5 TR 1382. As a result, the DCF results can be compared against the CAPM and ECAPM analyses, Risk Premium, and Comparable Earnings, and can be viewed as a low outlier. 5 TR 1382. In fact, regulators such as the Federal Energy Regulatory Commission ("FERC") have had concern with

[16]As further described below, earnings growth is an incorrect alternative.

overreliance on the DCF model because the average output of the DCF analysis would not provide sufficient risk premium to fairly compensate investors for the risks associated with owning the stock, particularly because equity owners have the lowest claim to Company assets and income. 5 TR 1382. Since the resulting average of the DCF clearly underestimates the required ROE, the Company's ROE recommendation properly considers the full range of results provided by the CAPM, ECAPM, DCF, Risk Premium, and Comparable Earnings analyses. 5 TR 1383.

iv. Comparable Earnings Analysis

References in the Record: Wehner (as adopted by Bleckman), 5 TR 1383-1384

Mr. Bleckman also used a Comparable Earnings Analysis to project ROEs for the Company's proxy group. Under this method, earned ROEs for the proxy group are based on earnings per share and book value per share from Value Line, which information is readily available to investors. 5 TR 1383. This is the same as the cost of equity for a regulated utility and provides a reasonable proxy of analyst and investor expectations for a regulated utility return.[17] 5 TR 1383. It is worth noting that in Case No. U-16794, the Commission specifically considered and gave weight to use of the ROE calculated using Value Line book value and earnings. 5 TR 1384. Mr. Bleckman's Comparable Earnings Analysis produced an average ROE of 11.22% and ranges from a minimum of 9.19% to a maximum of 15%. Exhibit A-14 (TAW-1), Schedule D-5, page 6. These results support the Company's request ROE of 10.25%.

[17] Because earnings in any single year can vary from the authorized ROE, results for multiple years need to be kept in mind while determining the cost of equity capital using this method. 5 TR 1383.

v. The Commission Should Disregard Intervening Parties' Criticisms of the Company's ROE Analyses, as the Criticisms Don't Modify the Demonstrated Reasonableness of the Company's Requested 10.25% ROE

a) Discounted Cash Flow

References in the Record: Bleckman, 5 TR 1325, Exhibit A-222 (MRB-31); Exhibit A-215 (MRB-24)

As observed in Mr. Bleckman's rebuttal testimony, Mr. Megginson, Mr. Coppola, and Mr. Walters disagree with the use of dividend growth rates in the DCF model. Bleckman, 5 TR 1325. Further, Mr. Walters disagrees with Mr. Bleckman's judgement when he removed low-end outlier results from his analysis and suggests instead that Mr. Bleckman should have relied on the median as the measure of central tendency. *Id.* For his part, Mr. Bandyk disagrees with the use of a constant growth DCF model. *Id.*

While disagreeing with these witnesses' specific concerns, Mr. Bleckman provided updated analysis to show to the Commission that the concerns do not affect the Company's reasoned recommendations. *Id.* By updating his DCF analysis with market data through August 31, 2024 and relying on the average EPS growth rates from three sources, Value Line, Yahoo! Finance and Zacks, and including the results from all observations, Mr. Bleckman calculated a mean ROE of 10.66% and a median ROE of 10.60%. Exhibit A-222 (MRB-31). These results are higher than the results of Mr. Bleckman's DCF models as filed in his adopted direct testimony and show that, if anything, the Company's recommended ROE reasonable could have been higher than 10.25%.

As for Mr. Bandyk's concerns, as shown in Exhibit A-215 (MRB-24), updating Mr. Bandyk's multi-stage DCF model using EPS growth rates calculates to a 10.80% result. *Id.* Again, none of these concerns ultimately provide any evidence to suggest a deviation from the Company's recommendation.

b) CAPM and ECAPM

Several of the witnesses in this proceeding have criticized the MRP used in Mr. Bleckman's CAPM and ECAPM analyses.

Staff's Concerns

References in the Record: Bleckman, 5 TR 1326-1329, 1376-1377, Exhibit A-223 (MRB-32); Megginson, 5 TR 3593-3594

Mr. Bleckman relied on the same methodology for estimating the MRP in this proceeding that he used in Case No. U-21490. 5 TR 1326. Mr. Megginson apparently has accepted that methodology because he also relied on Mr. Bleckman's estimate of the MRP from Case No. U-21490. *Id.* Mr. Bleckman rightfully stated that it is unreasonable to accept the methodology from a prior proceeding but then reject the results of that methodology now, simply because the person does not agree with the result produced pursuant to the current market conditions. *Id.* Mr. Megginson's reliance on the approach, but rejection of the result simply ignores the current market conditions.

The cost of equity is intended to be forward-looking and take into consideration the current and expected market conditions; therefore, it is unreasonable for Mr. Megginson to ignore current data in setting a recommended ROE. *Id.* Finally, the methodology that Mr. Bleckman relied upon is generally consistent with the methodology that has been approved and is relied on by the FERC. *Id.* The FERC relies on a constant growth DCF for the S&P 500 Index using projected EPS growth rates to estimate the market return and calculates the MRP as the difference between that return and a risk-free rate. 5 TR 1326-1327. Therefore, none of these criticisms change the fact that the Company's methodology for estimating the return on the market is reasonable and appropriate. 5 TR 1327.

Mr. Megginson also criticized the Company's ECAPM analysis. As explained multiple times in this proceeding, including Mr. Bleckman's rebuttal testimony, ECAPM addresses some of the flaws with CAPM – in particular, for low beta stock such as utilities. *Id.* Likewise, the research regarding the concerns with CAPM are numerous, some of which Mr. Bleckman noted starting on page 34 of his adopted direct testimony from Mr. Wehner. *Id.* Mr. Megginson does not address nor even acknowledge any of this research but seems to indicate that his application of a Value Line beta and long-term treasury rates completely address all shortcomings of CAPM and thus makes ECAPM unnecessary. *Id.* Mr. Bleckman points out that this is simply untrue and is demonstrated by widespread professional use of ECAPM in the regulatory arena with both long-term Treasury Rates and Value Line beta. *Id.*

Mr. Megginson did not present any third-party academic or practitioner support to counter the information and analyses that Mr. Bleckman provided regarding the use of ECAPM or how it addresses the shortcomings of the CAPM analysis. *Id.* Likewise, he did not corroborate his claim that the CAPM analysis he performed addresses the shortcoming addressed by ECAPM. *Id.* Mr. Bleckman fully acknowledged that the ECAPM does increase the resulting ROE output over a similarly performed CAPM. *Id.* However, this should not be a surprise, as it corrects for the understated return that exists for low beta securities. 5 TR 1327-1328. In direct testimony, Mr. Bleckman covered that adjusted betas are consistent with ECAPM application, as they were used in the ECAPM analysis performed by regulatory witnesses in numerous states and were deemed necessary in Dr. Morin's book, The New Regulatory Finance. 5 TR 1328. In sum, Mr. Megginson's position on ECAPM is contrary to the professional use of the method.

While rejecting ECAPM generally, Mr. Megginson also contended that the use of Value Line adjusted betas and long-term debt estimates accounts are improper in the ECAPM analysis.

5 TR 3593-3594. Mr. Bleckman, however, preemptively refuted this argument in direct testimony. 5 TR 1376-1377. He showed the use of Value Line adjusted betas are consistent with the application of ECAPM, and Mr. Megginson did not address this portion of the Company's testimony. Bleckman, 5 TR 1328.

ABATE's Concerns

Mr. Walters suggested concern that the projected risk-free rate used by the Company was overstated, and he questioned the use of the five-year beta estimate as reported by Value Line. 5 TR 1326. Referencing Dr. Robert Morin's work, Mr. Walters also questioned the alpha term that Mr. Bleckman relied upon in his ECAP analysis. 5 TR 1326. Using Dr. Morin's work results in a weighting of 0.25 on the market beta and 0.75 on the utility beta rather than Mr. Bleckman's methodology which weights the utility beta somewhat less at 0.14. *Id.*

Mr. Walters' apparent concern over the Company's used projected risk-free rate is without merit. The risk-free rate assumption is based on the Bloomberg forward curve estimate and therefore was based on forward market data as of the time testimony was being developed. 5 TR 1328. Applying a more current risk-free rate (4.10%) to Mr. Bleckman's CAPM as proposed by Mr. Walters, would result in an ROE of 11.99%, which is lower than the result presented in his direct testimony, but well above the Company's requested ROE of 10.25%. *Id.*

Mr. Walters' criticism of the Company's use of the Value Line betas in CAPM analyses is misguided. As Mr. Bleckman explained, Value Line betas are routinely relied upon by experts who estimate the cost of equity and are reasonable assumptions to rely on in the CAPM models. 5 TR 1329. In fact, Mr. Walters is the only witness in this proceeding who has established a range of CAPM results that vary based on the beta assumptions. *Id.* All other witnesses in this

proceeding rely on Value Line betas; therefore, it is reasonable and appropriate to continue to rely on this assumption. *Id.*

While the Company continues to support the MRP that Mr. Bleckman relied upon in direct testimony, as shown in Exhibit A-223 (MRB-32), updating to rely on Mr. Walters' estimated forward looking MRP, using the market return on the S&P 500, and Mr. Walters' risk-free rate of 4.10% instead, results in a CAPM ROE of 11.18% to 11.30%. *Id.* Further, the exhibit also demonstrates an ECAPM using the weightings preferred by Mr. Walters, assigning a 0.25 weighting to the market beta and a 0.75 weighting to the utility beta. *Id.* The result of this updated ECAPM are mean and median ROEs of 11.32% to 11.42%, again supportive of the Company's request as is, if not higher.

None of the CAPM and ECAPM criticisms of the intervenor witnesses in this proceeding change the Company's results such that they no longer support a requested ROE of 10.25%. While Mr. Bleckman does not necessarily agree with each of the criticisms offered, as demonstrated above, taking into consideration adjustments to the Company's models to reflect certain preferred assumptions demonstrate that his analyses would still, at a minimum, support the Company's requested ROE of 10.25%. *Id.*

c) Comparable Earnings Analysis

References in the Record: Coppola, 5 TR 2821; Walters, 5 TR 3437; Bleckman, 5 TR 1330-1331

Mr. Coppola considers the Company's comparable earnings analysis as an "alternative method" that should be disregarded by the Commission. 5 TR 2821. Mr. Walters argues that since the FERC has rejected the comparable earnings analysis, the Company's analysis should be

rejected too in this proceeding. 5 TR 3437. Finally, Mr. Megginson fails to include a comparable earnings analysis in his ROE estimation models entirely. Bleckman, 5 TR 1330.

As Mr. Bleckman pointed out, the DCF and CAPM models were developed decades after *Hope* and *Bluefield* were decided. *Id.* For years, the Comparable Earnings analysis was the standard for determining rate cases. *Id.* Newer models and techniques have since been developed, but the Comparable Earnings analysis is still relevant and in use today. *Id.* In Case No. U-16794, the Commission specifically considered and gave weight to determining the ROE using the Comparable Earnings analysis (referred to in the case as Value Line Book Value methodology) as follows:

> In so doing, the **Commission considers and gives weight to** Mr. Megginson's findings with regard to his average authorized ROEs analysis, which ranged from 10.28% to 10.36%, and to **Mr. Rao's Value Line Book Value method, which resulted in an average result for the proxy group of 10.50%. The median for this analysis was 10.42%. In light of these results, the Commission is comfortable in increasing the ALJ's recommended ROE by five basis points to 10.3%**. [MPSC Case No. U-16794, June 7, 2012 Final Order, page 65 (emphasis added).] 5 TR 1330.

From this, it is extremely clear that Mr. Rao's Value Line Book Value method, which is directly comparable to Mr. Bleckman's Comparable Earnings methodology, was directly considered in informing the Commission's 5 basis point increase from the ALJ's recommended ROE to 10.3% in the final order in that proceeding. 5 TR 1331. Further, as Mr. Bleckman points out, the FERC determined, in Docket No. EL11-66-001, that equal weighting to the Comparable Earnings analysis along with the DCF, CAPM, and Risk Premium methodologies was appropriate. *Id.* The comparable earnings analysis is a useful tool in ROE estimation that is well established and has regulatory support. *Id.* Thus, Mr. Coppola's and Mr. Walters' positions should be rejected.

d) Summary of the Intervening Parties' Concerns Over the Company's Analyses

As demonstrated in the aforementioned review of the Intervening Parties' concerns with the Company's analyses, the Commission may reasonably rely on the Company's estimates when establishing a 10.25% ROE. There is not substantial evidence to support a result to the contrary, and the Company has provided ample evidence to support its request. The Commission should set the Company's ROE at 10.25%.

c. Response to Staff's and Intervenors' Credit Analyses and Impacts

References in the Record: Bleckman, 5 TR 1277-1278, 1282-1284, 1286

Set forth below are the recommendations for the Company's authorized ROE and Equity Ratio:

	Megginson	Coppola	Bandyk	Walters
DCF Analysis				
Constant Growth DCF	10.76%	9.27%	n/a	10.99%-11.34%
Constant Growth DCF- Sustainable Growth Rate	n/a	n/a	n/a	8.90%-9.20%
Multi-Stage Stage DCF	n/a	n/a	8.95%	9.29%-9.31%
CAPM	9.77%-11.60%	10.58%	8.01%	8.94%-10.69%
Risk Premium	8.69%-10.27%	9.72%	n/a	9.96%-10.20%
Authorized ROEs				
2024 through June Avg. Auth'd Electric ROE	9.68%	n/a	n/a	n/a
2023 Avg. Auth'd Electric ROE	9.60%	n/a	n/a	n/a
2022 Avg. Auth'd Gas ROE	9.48%	n/a	n/a	n/a
2021 Avg. Auth'd Gas ROE	9.45%	n/a	n/a	n/a
Adjustment for other factors	n/a	0.09%	n/a	n/a
Existing Authorized ROE	n/a	n/a	9.90%	n/a
Recommended ROE Range	9.35% to 10.35%	n/a	n/a	
Recommended ROE	**9.85%**	**9.80%**	**9.19%**	**9.25%-9.5%**

Staff, the Attorney General, ABATE, and MNSC witnesses all recommended a reduction in the Company's authorized ROE while simultaneously also recommending lowering the Company's authorized equity ratio. These recommendations are not adequate returns to ensure the financial soundness of the business and are not sufficient to maintain credit and attract capital

when needed under reasonable terms. In addition to risking the Company's long-term financial strength, these recommendations are not in the best interest of the Company's customers because they would require the Company to operate at the margins given the underlying economic conditions (geo-political tensions, elevated inflation, elevated interest rates, etc.). There is significant risk that prudent management would attempt to avoid when providing the public with an essential service (which the Company is trying to do with its ROE recommendation to the Commission). 5 TR 1284. As for each party's recommendation to reduce the Company's ROE, each party offers virtually no discussion of how a reduced ROE (and equity ratio) will impact the Company's credit rating, and none recognize, appreciate, or even demonstrate an awareness that Moody's credit downgrade and S&P's credit downgrade warnings can and have actually negatively impacted the Company's credit metrics and the Company's ability to reasonably access credit. Importantly, they fail to demonstrate any concern regarding how those negative impacts cascade down to the Company's customers. See, 5 TR 1277-1278. The intervenor witnesses have advocated for decreases to the Company's financial metrics for several years in successive cases despite substantial market disruptions that are top of the mind for potential investors. 5 TR 1282-1284. Given current market conditions, they are pushing the Company toward credit downgrade thresholds. 5 TR 1286. In sum, the Commission should reject the attempt.

As will be discussed below, Staff and Intervenors also have not provided substantive evidence that economic conditions have changed so radically that a significant *downward* adjustment to the ROE is warranted. Conversely, there are numerous market forces as discussed earlier that have adversely impacted investor risk tolerance and justify an *increase* to ROE. Thus, the Commission should give little or no weight to their analysis as presented in favor of any downward adjustment to the Company's ROE.

i. Response to Staff's Quantitative Analysis

References in the Record: Bleckman, 5 TR 1277-1279, 1282-1284, 1286, 1289-1291

Staff utilized three models in determining the ROE for the comparable companies: CAPM, Risk Premium analysis, and the DCF. Megginson, 5 TR 3580.

Despite the fact that his analysis demonstrates a significant increase in the cost of equity since the Company's last rate proceeding, Mr. Megginson recommends a 5-basis point decrease in the Company's currently authorized ROE of 9.90%. 5 TR 1277. Mr. Megginson develops seven analytical models to estimate the cost of equity and considers authorized ROEs for electric utilities over four years (2021 through June 2024). 5 TR 1278. The simple average of these results is 9.93%, 8 basis points above his recommendation. 5 TR 1278. Making one reasonable adjustment to Mr. Megginson's CAPM results, to address the change in the methodology that he uses to estimate the risk-free rate, increases the result of that model such that the average of all of his analyses and authorized ROE summaries is 9.99%, 13 basis points above his recommendation. 5 TR 1278. Finally, comparing Mr. Megginson's analytical results in the current case to the results that he developed in the Company's last electric case (Case No. U 21389) demonstrates that the cost of equity has increased approximately 25 basis points, yet his recommendation increased only 5 basis points, which demonstrates that the range established by Mr. Megginson in the current proceeding, and his recommended ROE, undoubtably understate the cost of equity for Consumers Energy. 5 TR 1279. Because the range established by Mr. Megginson does not reflect the increase in the cost of equity that is demonstrated by his model results, the midpoint of that range, understates the Company's proper ROE. 5 TR 1289. In all, the directionality of his analysis from Case No. U 21389 to the case at hand demonstrates that the Commission should increase the Company's ROE.

With its recommended 10.25% ROE, the Company is trying to keep the best interests of its customers in mind and avoid having the Company operate at the margins given the underlying economic conditions (geo-political tensions, elevated inflation, elevated interest rates, etc.). 5 TR 1282-1284. Since the onset of the significant aforementioned financial and market impacts, Staff has not demonstrated an awareness that changing economic and financial challenges can arise that require managing for conditions that may not always be constructive. 5 TR 1284. Despite the growing list of "unforeseen" events that have occurred since 2020, including the credit downgrade the Company received from Moody's, Staff witness Megginson doesn't address the Federal Reserve's tightened financial conditions or the myriad of market disruptions that are top of mind for investors when assessing investment risk. 5 TR 1284. In fact, Staff seems to suggest, as it has in the past, that the utility should manage its balance sheet as if conditions have always been and will always be constructive. 5 TR 1284. But this optimistic economic outlook should not be relied upon by this Commission considering the unforeseen nature of recent global health issues, interest rate and inflationary concerns, and financial and geopolitical crises. 5 TR 1284. Waiting until problems arise, another downgrade occurs, or capital is difficult to source, to take supportive action is simply not representative of prudent management of an essential public service. 5 TR 1284.

At this point in showing the shortcomings in Staff's analysis, it is worth noting that the composition of the proxy groups is not the primary difference in the analytical results between Mr. Megginson and the Company's witness, Mr. Bleckman. 5 TR 1291. As discussed below, certain other inputs do however affect the reliability of Staff's results.

Mr. Megginson utilizes authorized ROE data from 2021 and 2022. 5 TR 1290. However, Mr. Megginson relies on bond yield risk premium analysis, which suggests that he recognizes that there is a relationship between interest rates and the cost of equity for regulated utilities. 5 TR

1290. Withholding for now that there are issues with his bond yield risk premium analysis, which will address below, it is unreasonable to suggest that the authorized ROE in 2021 would be a meaningful indicator of the cost of equity in the current market conditions. 5 TR 1290. While Mr. Megginson notes that the average authorized ROE for electric utilities was 9.45% in 2021, the average yield on the 30-year Treasury bond at that time was 2.05%, and in 2022 it was 3.11%. 5 TR 1290. In contrast, the average yield on the 30-year Treasury bond in the first six months of 2024 was 4.46%. 5 TR 1290. Further, Mr. Megginson relies on a projected interest rate of 3.65% in his CAPM analysis. 5 TR 1290-1291. While the Company disagrees with his calculation of that risk free rate, as will be discuss below, even this estimated interest rate is 160 basis points higher than the average interest rate in 2021. 5 TR 1291. Based on these differences in market conditions, it is unreasonable to rely on the 2021 and 2022 authorized ROEs[18] to set the ROE for Consumers Energy in this proceeding. 5 TR 1291. In sum, excluding the 2021 and 2022 authorized ROE data, the average ROE using Mr. Megginson's own analyses is 10.04%. 5 TR 1291.

As discussed below in more detail, Staff's analysis does not appropriately account for the underlying assumptions of each of the quantitative models, and its failure to do so necessarily results in Staff's ROE recommendation being too low. Beyond summary conclusions, Staff's analysis does not even support its own recommendations. Therefore, Staff's ROE recommendation at 9.85% is not supported by substantial evidence in the record, and the Commission should reject in favor of the Company's recommended 10.25%.

[18] Mr. Megginson reports the authorized ROEs for 2021 and 2022 to be 9.45% and 9.48%; however, in Case No. U-21389, he reports a higher average authorized ROE for 2022 of 9.54% and for 2021 he reports a lower average authorized ROE of 9.38%. The inconsistencies in his analysis of this historical information is further reason not to rely on this data. 5 TR 1291.

a) Staff's CAPM Analysis is Flawed

References in the Record: Bleckman, 5 TR 1303-1311

Mr. Megginson conducts two CAPM analyses, one using a historical MRP, and another using the Company's projected MRP from Case No. U-21389. 5 TR 1303. For both of his CAPM analyses, Mr. Megginson relies on (1) a risk-free rate of 3.65%, which is based on a weighted average of projected 30-year Treasury bond yields for 2024 through 2026 as reported by S&P Global Market and econforecasting.com; and (2) current betas for each of his proxy group companies as published by Value Line. 5 TR 1303. Mr. Megginson's historical MRP of 6.80% is calculated using two different methodologies. 5 TR 1303. For the period from 1928-2022, Mr. Megginson calculates the MRP as the mean realized return on large company stocks minus the income-only total return on long term government bonds over that same period. 5 TR 1303. For the last year, Mr. Megginson notes that the data set he relied upon was no longer updated, so he changed his calculation in the last year to be the total market return as published by Mr. Damodaran less the yield on the U.S. Treasury securities at constant maturity. 5 TR 1303-1304. Mr. Megginson relies on two projected market risk premia, the Company's estimated MRP of 8.48% in the current case and the Company's estimated MRP of 6.53% from Case No. U-21389. 5 TR 1304. As shown in Exhibit S-4, Schedule D-5, pages 7 through 9, the results of those analyses are 10.03% (historical MRP), 9.77% (projected MRP from Case No. U-21389), and 11.60% (projected MRP in the Company's testimony in the current proceeding). 5 TR 1304. There are flaws in Mr. Megginson's risk-free rate and MRP.

Risk Free Rate

Mr. Megginson's weighting of his projected risk-free rates is not consistent with his testimony in the Company's last electric rate case proceeding and results in the lowest estimated risk-free rate of the range relied upon by the witnesses in this proceeding. 5 TR 1304.

Mr. Megginson developed his risk-free rate by weighting projections of the risk-free rate for 2024 through 2026; however, the weightings that he relied upon in this proceeding are significantly different than the weightings that he used in the previous case. Bleckman, 5 TR 1304. In Case No. U-21389, Mr. Megginson gave 25% weight to the current year and 75% weight to the second-year projection in his analysis. 5 TR 1304. In the current case, Mr. Megginson weighed the current year only 5%, 2025 was given a 90% weight, and 2026 was given a 5% weight. 5 TR 1304. Given the uncertainty in forecasts, it is reasonable to weigh the current year greater than the projected years. 5 TR 1305.

Market Risk Premium

There are multiple concerns with Mr. Megginson's use of a historical MRP from a methodological perspective and specific concerns with certain of the calculations of the MRP. 5 TR 1306. Fundamentally, the market return and MRP should be forward-looking. As Morningstar has observed, the MRP is a forward-looking concept, not a historical analysis:

> It is important to note that the expected equity risk premium, as it is used in discount rates and the cost of capital analysis, is a forward-looking concept. That is, the equity risk premium that is used in the discount rate should be reflective of what investors think the risk premium will be going forward.

Mr. Megginson (and Mr. Coppola) have not provided any evidence that the historical averages that they calculate for the market return or the MRP reflect the expected market conditions during the period in which the Company's proposed rates will be in effect. 5 TR 1306. Additionally, Mr. Megginson's estimate of the historical MRP, is further flawed because he relies on two data sets to calculate the historical MRP. 5 TR 1306.

Mr. Megginson attempted to splice together two data sets to estimate the MRP, and in doing so understated the MRP as of the end of 2023. 5 TR 1306. Mr. Megginson states that Kroll no longer provides the annual data to estimate the MRP and therefore he relied on two other data

sources to estimate the MRP. 5 TR 1306-1307. The flaw in this analysis is that Mr. Megginson did not determine, through any analytical means, that the use of these two new data sets to estimate the 2023 MRP were similar to the historical data that he relied upon from 1928 through 2022. 5 TR 1307. Without that analysis it was incorrect to simply average the 2023 MRP from new sources with the historical data set. 5 TR 1307. While it is true, that Kroll no longer provides the underlying components of their calculated MRP, Kroll does still publish the historical average MRP annually. 5 TR 1307. As of the end of 2023, which is the data set Mr. Megginson attempted to estimate, Kroll continued to estimate a MRP of 7.17%. 5 TR 1307. Therefore, Mr. Megginson's use of multiple data sets underestimates the MRP in his CAPM analyses. 5 TR 1307.

Another reason why Mr. Megginson (and Mr. Coppola) using the historical MRP is not appropriate in the calculation of the CAPM based on current market conditions is that he disregards the demonstrated relationship between interest rates and the MRP. 5 TR 1307. Mr. Megginson (and Mr. Coppola) calculate the cost of equity using the CAPM by relying on a long-term historical average market risk premia and a near-term projected risk-free rate. 5 TR 1307. However, in Mr. Megginson's (and Mr. Coppola's) specification of the CAPM, his respective near-term projected risk-free rates bear no relationship to the historical average interest rates underlying the historical average market risk premia on which he relies. 5 TR 1307. Therefore, the use of assumptions from different time periods fails to account for the inverse relationship that exists between the risk-free rate and the equity risk premium. 5 TR 1307. Both academic literature and market evidence indicate that the equity risk premium is inversely related to the level of interest rates (i.e. as interest rates increase, the equity risk premium decreases, and vice versa), and given that current interest rates on long-term government bonds are below the historical average interest

rate of those same bonds, the MRP should be greater than the long-term historical average MRP – which is not the case for Mr. Megginson's (and Mr. Coppola's) CAPM analyses. 5 TR 1307-1308.

Kroll, the publisher of the historical data on which Mr. Megginson (and Mr. Coppola) rely to estimate the historical MRP, highlighted a potential inconsistency with relying on historical data for a forward-looking analysis such as the CAPM (5 TR 1309) Kroll stated that, "[i]n using a historical measure of the equity risk premium, one assumes that what has happened in the past is representative of what might be expected in the future." 5 TR 1309. However, because the near-term projected long-term government bond yields are currently below those that Mr. Megginson (and Mr. Coppola) have relied on in their historical average MRP estimates, the MRP based on long-term historical average data is certainly not representative of what is expected in the future. 5 TR 1309. Given the inverse relationship between the MRP and interest rates, since the projected interest rate is lower than the historical average, it is correct to expect that the MRP would be higher than the historical average. 5 TR 1309.

In fact, the use of a historical market premium can produce counter-intuitive results. Specifically, from 2007-2009, the historical MRP decreased even as market volatility (the primary statistical measure of risk) significantly increased. 5 TR 1309-1310. Further, Mr. Bleckman's testimony demonstrated the significant swings in the annual equity risk premium that are averaged into the long-term historical average calculations. 5 TR 1310. In 2008, the annual equity "premium" was actually negative, which implies a discount for equity holders relative to the cost of debt. *Id.* It is incomprehensible that the perceived risk for equity was negative (implying a lower required return) in the height of the financial market collapse when the overall market return was a negative 37%. *Id.* This observation alone, which clearly runs counter to the theory of the

equity risk premium, reduces the historical average MRP for the prior 80 years by 60 basis points. *Id.*

The assumption that investors would expect or require a lower equity risk premium during periods of increased volatility is counter-intuitive and leads to unreliable analytical results. *Id.* As noted earlier, the relevant objective in the application of the CAPM is to ensure that all three components of the model (i.e. the risk-free rate, the beta, and the MRP) are consistent with market conditions and consequently investor perceptions. *Id.* To the contrary of Staff's analysis, the forecasted MRP estimates used in the Company's original and rebuttal CAPM analyses specifically address that concern. *Id.*

Staff produces two projected CAPM analyses – one utilizing the Company's MRP estimate of 8.48% and another applying a MRP estimate of 6.53%. 5 TR 1311. This MRP was not produced or supported in the record of this instant case, but rather, the estimate was developed in Case No. U-21389 using the same methodology at that time. *Id.* While the 6.53% MRP estimate was supported and applicable in its own case, it is not applicable in this instant case, and it is unsound to pick certain portions of a past analysis to be applied in any analysis in this case only to deliver a lower ROE estimate, while negating the reliability of the analysis. *Id.* Therefore, by relying on a 6.53% MRP in that CAPM analysis, Mr. Megginson has disqualified the analysis from being able to provide substantial evidence in the record for Staff's 9.85% ROE recommendation.

The aforementioned disqualification is significant and appears to compound and then fully discredits Mr. Megginson's assessment of his own CAPM ROE analysis. *Id.* When describing the projected CAPM analysis, Mr. Megginson concludes that the one lower ROE estimate is reasonable, and the other is not. *Id.* He accepts his estimate that cherry picks a single data piece from a previous and outdated case as reasonable but then rejects a higher estimate, concluding that

it is outside the "realm of reasonableness;" without sharing how he specifically determined the boundaries of his perceived realm. *Id.* While the resulting estimates may have gone up dramatically since Case No. U-21389, this does not mean that they should be ignored altogether, and no less in favor of portions of past analysis that are unsupported in the current case. *Id.* The simple conclusion is, to the contrary of Mr. Megginson's assertion, that equity risk premiums are currently at the high end of normal historical ranges. *Id.* Mr. Bleckman states that this is driven by the market volatility and uncertainty referenced in his direct testimony. *Id.* The direction of the analysis estimates and magnitude of change could be informative and further supportive of the very increase to ROE that the Company has recommended in this case. *Id.* The Commission should adopt the Company's requested ROE at 10.25%

b) Staff's Risk Premium Analysis is Flawed

References in the Record: Bleckman, 5 TR 1315-1317; Wehner (as adopted by Bleckman), 5 TR 1378

Mr. Megginson's risk premium analyses use the risk premium over utility bonds ("Utility Bond Spread") and the risk premium over long-term Treasury bond yields ("Treasury Bond Spread"). Bleckman, 5 TR 1315-1316.

Mr. Megginson's Utility Bond Spread analysis calculates the MRP as the difference between the historical average market return on electric utility stock returns less historical average utility bond yields over the period of 1932 to 2023. Bleckman, 5 TR 1316. He estimates the ROE by adding a current long-term utility bond return on A and BBB rated utility bonds. *Id.* The result of this analysis is 9.94% to 10.27%. *Id.*

Mr. Megginson's Treasury Bond Spread analysis calculates the risk premium using the historical average realized return on electric utility stock from 1932 to 2023 less the realized returns on Treasury bonds over the period from 1955 to 2023. *Id.* He estimates the ROE by adding

a current Treasury bond yield to this risk premium. (rebuttal 99) The ROE estimate from this methodology is 8.69%. *Id.*

Mr. Megginson's analysis is flawed in that he relies on averages from two different time periods for his return on electric utility stocks and the returns on treasury bond yields. Bleckman, 5 TR 1317. Since investors can choose to invest in either a company's debt or equity, depending on the relative advantages of debt versus equity, based on market conditions at a particular time, it is simply incorrect to calculate a risk premium using average electric utility stock returns over the period from 1932 through 2023 and subtracting from that the average return on government bonds over a different time-period, from 1955 through 2023. Wehner, 5 TR 1378; Bleckman, 5 TR 1317. As suggested in Mr. Bleckman's direct testimony, Risk Premium Analysis without careful consideration of Federal Reserve action in time renders the application of the historical data less reliable. Wehner, 5 TR 1378. However, since the averages used by Mr. Megginson reflect market conditions from different periods, the calculated MRP as he presented is invalid and cannot be relied upon at all. Bleckman, 5 TR 1317.

c) Staff's DCF Analysis Supports the Company's Requested ROE at 10.25%

References in the Record: Bleckman, 5 TR 1293-1294

Mr. Megginson conducted a constant growth DCF, and for each of his proxy group companies relied on (1) an average of closing monthly stock prices as of June 1, July 1, and August 1, 2024; (2) annualized dividends that reflect one half of the estimated growth rate; and (3) projected EPS growth rates from Value Line, Yahoo! Finance, and Zacks Investment Research ("Zacks"). Bleckman, 5 TR 1293. The mean result of Mr. Megginson's "traditional DCF" analysis result is 10.76%, which is significantly higher than the Company's requested ROE of 10.25%. Bleckman, 5 TR 1294.

Clearly, this result is only substantial evidence in favor of an increase in the Company's ROE.

d) In Addition to Staff's DCF Analysis as is, with Valid and Proper Adjustment Staff's CAPM Analysis and Risk Premium Analysis are Supportive of the Company's Proposed ROE

References in the Record: Bleckman, 5 TR 1314-1317, 1321, Exhibits A-217 (MRB-26), A-218 (MRB-27), A-219 (MRB-28)

As stated above, Mr. Megginson conducts a constant growth DCF. The average cost of equity resulting from Mr. Megginson's constant growth DCF analysis is 10.76% which is significantly higher than the Company's requested ROE of 10.25%. Therefore, at a minimum it supports an increase to the Company's ROE.

With valid adjustments to Mr. Megginson's CAPM analyses to correct the risk-free rate and to adjust the historical MRP, the analysis supports the Company's requested ROE and in fact exceeds it. Just updating Mr. Megginson's historical CAPM analysis for a risk-free rate that relies on weightings similar to what he used in the last electric rate proceeding (which will still be the lowest risk-free rate used in this proceeding), increases the median of his historical CAPM to a 10.22% ROE, a mere three basis points below the Company's requested ROE of 10.25%. Bleckman, 5 TR 1314-1315. Adding in an adjustment to include Kroll's 7.17% MRP as of the end of 2023, which is the data set Mr. Megginson attempted to estimate, results in a 10.57%[19] ROE. *Id.* These adjustments are proper given the flaws in Mr. Megginson's CAPM analysis that are pointed out above. If anything, Staff's CAPM analysis supports an increase in the Company's ROE. No other conclusion is supported by the evidence.

[19] Relying on the underlying calculations contained in A-217 (MRB-26), the Company notes that there is a copying error (typo) on page 98 of Mr. Bleckman's Pre-filed Rebuttal testimony. The correct number is 10.57%. As stated above, 10.22% is the result of only updating Mr. Megginson's historical CAPM analysis for a risk-free rate that relies on weightings similar to what he used in the last electric rate proceeding.

As discussed above, Staff presented two sets of Risk Premium Analysis. Mr. Megginson conducted a Utility Bond Spread analysis which calculates the MRP as the difference between the historical average market return on electric utility stock returns less historical average utility bond yields over the period of 1932 to 2023. Bleckman, 5 TR 1315-1316. Mr. Megginson calculated an estimated ROE of 9.94% to 10.27% by adding a current long-term utility bond return on A and BBB rated utility bonds. Bleckman, 5 TR 1316. These results are not unsupportive of the Company's requested 10.25% ROE.

As discussed more thoroughly above, Mr. Megginson also conducted a Treasury Bond Spread risk premium analysis. However, as presented it is flawed because he relies on averages from two different time periods for his return on electric utility stocks and the returns on treasury bond yields. Bleckman, 5 TR 1317. To correct the flaws, Mr. Bleckman calculated the average Treasury bond yield from 1932-2023 to be consistent with the time period that Mr. Megginson used for the total return on the electric utility stocks. As shown in Exhibit A-218 (MRB-27), the updated average treasury bond yield is 4.95%, resulting in a historical treasury bond spread of 5.83%. In Exhibit A-219 (MRB-28), Mr. Bleckman then presented the corrections to Mr. Megginson's Risk Premium analysis to reflect the inverse relationship between interest rates and the MRP, using consistent data back to 1932, and his update to Mr. Megginson's projected risk free rate of 3.76%. Bleckman, 5 TR 1319. Adding the historical treasury bond spread to the long-term treasury bond yield, which is based on the correction noted previously to Mr. Megginson's treasury bond yield calculation, the resulting cost of equity for Mr. Megginson's Treasury Bond Approach results in a calculated 9.59% ROE estimate. *Id.* These valid and proper corrections thus represent an increase of 91 basis points from the estimate that Mr. Megginson provided in his analysis. *Id.*

To summarize, Mr. Bleckman presented the results of Mr. Megginson's cost of equity analyses based on the updates and corrections to those analyses explained above as follows:

- An adjustment to Mr. Megginson's CAPM analyses to correct the risk-free rate and to correct the historical MRP;
- A correction to Mr. Megginson's Treasury bond yield risk premium approach to use consistent averaging periods in the development of the risk premium and to update the risk-free rate; and
- The elimination of the 2021 and 2022 average authorized ROEs because those ROEs were established in different market conditions than the present. Bleckman, 5 TR 1320..

As shown in Figure 7 from Mr. Bleckman's rebuttal testimony, reproduced below, the average of Mr. Megginson's analyses are 10.24% to 10.27%, depending on how the risk premium results are averaged. 5 TR 1321. These results are generally consistent with and supportive of the Company's requested ROE of 10.25%. The results clearly do not support any reduction to the Company's ROE.

Figure 7: Results of Mr. Megginson's As-Filed and Adjusted Cost of Equity Analyses

		Mr. Megginson As Filed	Mr. Megginson As Adjusted
Constant Growth DCF	[1]	10.76%	10.76%
CAPM			
Historical Market Risk Premium		10.03%	10.57%
Projected Market Risk Premium		9.77%	9.96%
Projected Market Risk Premium		11.60%	11.60%
Average	[2]	10.47%	10.71%
Historical Market Risk Premium Only	[3]	10.03%	10.57%
Risk Premium			
Utility Bond Risk Premium (A-rated)		9.94%	9.94%
Utility Bond Risk Premium (BBB-rated)		10.27%	10.27%
Treasury Bond Risk Premium		8.69%	9.59%
Average	[4]	9.63%	9.93%
Authorized ROEs			
2023 Avg. Auth'd Gas ROE		9.60%	9.60%
2024 Avg. Auth'd Gas ROE	[5]	9.68%	9.68%
Average of [1], [2], [4], [5]		**10.14%**	**10.27%**
Average of [1], [3], [4], [5]		**10.03%**	**10.24%**
Recommended ROE		9.85%	
Company's Proposed ROE			10.25%

Bleckman, 5 TR 1321.

While Mr. Megginson states that the results of the Company's risk premium analysis "appears inflated," Mr. Megginson provides no data, analysis, or support for this claim other than stating that the Company's results are higher than Staff's. Bleckman, 5 TR 1317. The fact that the Company's risk premium analysis produced a higher ROE estimate than Mr. Megginson does not mean that the result is therefore inflated. The results speak for themselves as calculated. Having not provided any analysis to support Mr. Megginson's claim, the Commission should reject his recommendation, and the Commission should give weight and careful consideration of the Company's risk premium analysis.

ii. Response to the Attorney General, ABATE, and MNSC's Quantitative Analysis

References in the Record: Bleckman, 5 TR 1279, 1291-1292, Exhibit A-225 (MRB-34)

While there are issues with numerous assumptions relied upon by Attorney General witness Coppola, the two primary areas where his analytical results faulter are as follows: the omission of growth rates in the DCF model and the risk-free rate relied upon in the Risk Premium analysis. Bleckman, 5 TR 1279. Despite these errors, and as more fully described below, with reasonable adjustments to those models, Mr. Coppola's analyses result in ROE estimates that exceed the Company's requested ROE. *Id.*

Mr. Coppola changed the methodology that he relied upon in evaluating the growth rates in his DCF model in this proceeding, as compared with his testimony in Consumers Energy's most recent electric rate proceeding, with the result of reducing his DCF model result. *Id.* Updating his DCF analysis to include growth rates that are 7% or greater, which he readily included in his prior analyses, increases his DCF result by 124 basis points to 10.51%. *Id.*

Updating Mr. Coppola's risk premium analysis to rely on the same risk premium used by Mr. Megginson increases his risk premium model results 44 basis points to 10.16%. *Id.* Applying

Mr. Coppola's weightings to these updated models (leaving his CAPM unchanged) results in an ROE of 10.44%, all of which demonstrate that the Company's requested ROE is reasonable. *Id.*

Although the composition of the proxy group in not the primary difference in analytical results between Mr. Megginson and Mr. Bleckman, it is worth discussing that Mr. Megginson does rely on proxy groups that differ substantially from the proxy group that Mr. Bleckman used. Bleckman, 5 TR 1291-1292. Mr. Coppola made changes to his screening criteria in this proceeding that were not included in the Company's last proceeding. Bleckman, 5 TR 1292. In this proceeding, Mr. Coppola added wildfire risk as a screening criterion. *Id.* In addition, he excluded WEC Energy Group, Inc. ("WEC") on the basis that the company had acquired a solar energy project. In response to a discovery request, Mr. Coppola acknowledged that wildfire risk has been public knowledge for the past seven years; however, he did not include this screening criterion in establishing his proxy group in Case No. U 21389. *Id.*; Exhibit A-225 (MRB-34). Further, Mr. Coppola's decision to exclude WEC from the proxy group based on the acquisition of the solar project is not justified. *Id.* As also noted in the discovery response shown on Exhibit A-225 (MRB-34), Mr. Coppola has not conducted any analysis to demonstrate that the WEC market data was affected by this transaction. *Id.* Mr. Coppola simply suggests that it is likely that this acquisition would have affected the stock price, earnings growth rate, and dividend yield for WEC, and suggests because of the "potential impact on factors impacting the calculation of the cost of equity, WEC was not a good candidate to be included in the peer group." *Id.* That is not a justification. *Id.*

a) The Attorney General's CAPM Analysis Supports the Company's Requested ROE at 10.25%, and By Adding Valid and Proper Adjustment, Including the Attorney General's Risk Premium Analysis and DCF Analysis, the Attorney General's Analyses Together Support the Company's Requested ROE

Mr. Coppola conducts a CAPM analysis that relies on (1) a risk-free rate of 3.95%, based on the S&P Global economics projection provided by the Company for the 10-year Treasury bond yield; (2) current betas for each of the proxy group companies as published by Value Line; and (3) a MRP of 7.17%, which is the historical market return of large company stocks minus the income-only return on long-term government bonds from 1926 through 2022 as published by Kroll. Bleckman, 5 TR 1304. Despite reliance on a historical MRP, as discussed above in review of Mr. Megginson's analysis, Mr. Coppola's CAPM results support the Company's requested ROE. Bleckman, 5 TR 1315. The mean result of his CAPM analysis is 10.58%, which demonstrates that the Company's requested ROE is reasonable. *Id.* At a minimum and its most general, it is substantial evidence to demonstrate the directionality that there should be an increase in the Company's ROE.

Mr. Coppola's Utility Bond Risk Premium methodology is similar to Mr. Megginson's Utility Bond Spread, as Mr. Coppola's analysis reflects the historical equity risk premium of electric utility stock returns less A-rated utility bond yields plus a projected average yield on A-rated and BBB-rated utility bonds. Bleckman, 5 TR 1316. Mr. Coppola's risk premium model produces a cost of equity of 9.72%. *Id.*

Mr. Coppola's Utility Bond Risk Premium methodology is in error in that it is unclear how Mr. Coppola developed his utility bond risk premium of 4.07%. Bleckman, 5 TR 1318. However, it is reasonable to assume that the utility bond risk premium would be the difference between the electric utility total returns and the electric utility historical bond yields. *Id.* As shown in Exhibit

A-220 (MRB-29), updating Mr. Coppola's analysis to rely on the same historical risk premium that was calculated by Mr. Megginson results in an ROE estimate of 10.16%. Bleckman, 5 TR 1319. This result is of course only nine basis points below the Company's requested ROE at 10.25%, and once again shows that the evidence in this case only supports an increase in the Company's ROE.

Mr. Coppola conducted a DCF analysis. However, he changed the methodology that he relied upon in evaluating the growth rates in his DCF model in this proceeding, as compared with his testimony in Consumers Energy's most recent electric rate proceeding, with the result of reducing his DCF model result. Bleckman, 5 TR 1279. Updating his DCF analysis to include growth rates that are 7% or greater, which he readily included in his prior analyses, increases his DCF result by 124 basis points to 10.51%, which is of course higher than the Company's requested ROE of 10.25%. *Id.*

For each of his proxy group companies in his constant growth DCF, Mr. Coppola relies on (1) an average of the 30-day high and low stock prices; (2) projected dividends as reported by Value Line; (3) analysts' projected EPS growth rates as published by Yahoo! Finance and calculated projected EPS growth rates using actual EPS for 2023 and projected EPS for 2028 as published by Value Line. Bleckman, 5 TR 1293. As initially presented, the average cost of equity from Mr. Coppola's constant growth DCF analysis is 9.27%. *Id.*

Mr. Coppola's application of the DCF methodology in this case is inconsistent with the approach that he relied upon in the Company's last electric rate proceeding, Case No. U-21389. Bleckman, 5 TR 1294. The effect of the changes he makes in this proceeding is to understate the results of his analyses. *Id.* Specifically, in Case No. U-21389, Mr. Coppola excluded growth rates from his constant growth DCF analysis that were below 2%, which presumably is based on the

assumption that growth in perpetuity certainly should be no lower than the rate of inflation, again, at a minimum. *Id.* While Mr. Bleckman agrees with that assumption, and finds that it is appropriate in the current proceeding, Mr. Coppola added a second exclusion: growth rates above 7%. *Id.* This change in his methodology, which was not applied to his analysis in the Company's last electric rate case, has the effect of reducing the overall result of his analysis. As shown in Exhibit AG-1.18, and in Exhibit A-213 (MRB-22) where Mr. Bleckman recreated Mr. Coppola's DCF analysis, he reports the growth rates for Alliant Energy as "N/M" from Value Line and Yahoo. 5 TR 1294-1295. However, the actual growth rates for these companies are 7.00% and 7.70%, respectively.

In Case No. U 21389, Mr. Coppola relied on growth rates as high as 8.50% in his DCF analysis in that proceeding. Bleckman, 5 TR 1295. On page 98 of his direct testimony, Mr. Coppola states that he placed a fairly high degree of reliability in the DCF results when considered in conjunction with the results of other methods. *Id.* However, this reliance on DCF results is misplaced because of the model's sensitivity to short-term earnings volatility. *Id.* Additionally, Mr. Coppola's decision to give more weight to his DCF results over other methodologies is also misplaced. *Id.* Mr. Coppola provides no support or justification for how he has determined the appropriate level of weighting to be 200% more on the DCF analysis versus the alternatives. *Id.* It should be noted, however, that his chosen weighting and overreliance upon his lowest estimate results in a reduction in his resulting ROE estimate by 15 basis points. *Id.* Absent any justification, Mr. Coppola's choice to weight his DCF results in this manner should be considered arbitrary and rejected by the Commission. Bleckman, 5 TR 1295-1296.

Mr. Coppola's DCF analysis contains other errors in the growth rates. Bleckman, 5 TR 1296. Mr. Coppola reports "N/M" for the Yahoo EPS growth rate for PNM Resources. *Id.*

Though Yahoo reports a growth rate for PNM Resources of 4.42% as of the end of July, and 3.78% as of the end of August, under their new ticker "TXNM." Bleckman, 5 TR 1295-1296. In addition to this excluded growth rate, Mr. Coppola has a calculation error in the average growth rate for Consolidated Edison. *Id.* Rather than calculating the average growth rate for this company, Mr. Coppola only uses the average growth rate used in his DCF analysis. Bleckman, 5 TR 1296.

In his rebuttal testimony, Mr. Bleckman corrected Mr. Coppola's DCF analyses based on the changes discussed above. 5 TR 1302. Exhibit A-213 (MRB-22) includes the growth rates that Mr. Coppola excluded for Alliant Energy. *Id.* In addition, it includes the 3.78% growth rate for PNM Resources as of the end of August. *Id.* Finally, it includes the correctly averaged growth rates presented for Consolidated Edison. *Id.* The updated result to Mr. Coppola's DCF analysis is 10.51%. *Id.*

b) <u>ABATE's CAPM Analysis, Risk Premium Analysis, and DCF Analysis Updated, with Valid and Proper Adjustment, Support the Company's Requested ROE</u>

ABATE witness Walters relied on the same proxy group for his cost of equity analyses as the Company relied upon in direct testimony. Bleckman, 5 TR 1292. The primary areas of disagreement with Mr. Walters' analyses are (1) the change in how he weights his various DCF methodologies, as compared with his prior testimonies in other cases, and (2) the long-term growth rate used in his multi-stage DCF analysis and his reliance on the results of his Kroll MRP CAPM results that are well below the mainstream authorized ROEs for electric utilities. Bleckman, 5 TR 1280.

Adjusting Mr. Walters' long-term growth rate in his multi-stage DCF analysis increases the results from that model by 93 to 95 basis points to 10.22% and 10.26%. While Mr. Bleckman does not necessarily agree with Mr. Walters' sustainable growth rate DCF analysis, applying equal

weight to all three of his DCF models (after correcting his multi-stage DCF analysis) increases the results of his DCF to 10.04% to 10.27%, which is an increase of 31 to 32 basis points. Excluding the Kroll MRP scenarios from Mr. Walters' CAPM scenarios, the mean and median results of all of the remainder of his analyses are 10.22% and 10.30%, respectively. *Id.*

Mr. Walters conducts a CAPM analysis, producing 12 different cost of equity estimates from his CAPM analysis, relying on different estimates of the risk-free rate, beta, and MRP. Bleckman, 5 TR 1304. Mr. Walters relies on a projected 30-year Treasury yield in nine scenarios for his risk-free rate, and a Kroll "normalized" risk-free rate in the remaining three scenarios. Mr. Walters relies on four beta estimates: (1) current five-year betas published by Value Line; (2) historical average betas published by Value Line; (3) current beta estimates from S&P Market Intelligence's Beta Generator ("Market Intelligence"); and (4) current three-year raw betas published by S&P and then adjusted using the Blume adjustment applied by Value Line. Bleckman, 5 TR 1304-1305. For the MRP, Mr. Walters also relies on three estimates: (1) the long-term historical arithmetic average real return on the S&P 500 plus an expected inflation rate; (2) a constant growth DCF-derived return on the S&P 500, averaging the method prescribed by the FERC in Order No. 569-A with an alternative where all the companies in the S&P 500 are used rather than just the dividend-paying companies, less the risk-free rate; and (3) a "normalized" MRP published by Kroll. Bleckman, 5 TR 1305. Mr. Walters' CAPM results produce a cost of equity range from 8.21% to 10.80%. *Id.*

It is not reasonable to rely on the CAPM scenarios using the Kroll normalized MRP as developed by Mr. Walters. Bleckman, 5 TR 1313. The Kroll "normalized" MRP is inconsistent with the well-established inverse relationship between interest rates and the MRP (i.e. as interest rates increase, the MRP decreases, and vice versa). *Id.* Specifically, as shown on Exhibit AB-21,

page 1, in the CAPM scenarios in which Mr. Walters relies on the Kroll "normalized" MRP of 5.00%, he also relies on a normalized risk-free rate of 4.53%. *Id.* However, the long-term historical arithmetic average income-only return on long-term government bonds as published by Kroll is 4.87% and the corresponding long-term historical arithmetic average MRP over that same time period is 7.17%. *Id.* Thus, the risk-free rate relied on by Mr. Walters of 4.53% is lower than the long-term historical arithmetic average interest rate of 4.87%, indicating that, as just discussed, a lower interest rate would correspond to a higher MRP than 7.17%. *Id.* Therefore, taking into consideration the inverse relationship between interest rates and the MRP, Mr. Walters has relied on a MRP of 5.00%. which substantially understates the MRP in market conditions in an interest rate environment where the risk-free rate is 4.53%. *Id.* Relying on a MRP that is internally inconsistent with his risk-free rate renders the results of three of his 12 CAPM models, which rely on his "normalized" MRP, unreliable. Bleckman, 5 TR 1314.

Mr. Walters purports to estimate a "forward-looking" MRP. *Id.* However, first, it is important to recognize that Mr. Walters' risk premium-derived estimate of the market return is not "forward-looking." *Id.* Mr. Walters estimates this market return by applying a projected inflation rate to a long-term historical average market return. The result of this calculation is not a "forward-looking" market return. Second, while the use of historical average real return of the S&P 500 from 1926 through 2022 may reflect the returns realized by investors under various market and economic conditions, Mr. Walters provides no evidence that this calculation can or should reflect the market-required return in the current and expected market environment or the time period when the rates that are established in this case will be in effect. *Id.*

As shown in Figure 6 below, as recreated from Mr. Bleckman's testimony, while acknowledging differences with Mr. Walters' estimate of the market return, which affects his

market-derived MRP scenarios, the average result of these methodologies is 10.40%, which demonstrates that the Company's requested ROE of 10.25% is reasonable. 5 TR 1315.

Figure 1: Summary of Walters' "projected" MRP CAPM results

	Risk Premium Derived MRP	Average FERC S&P 500 DCF Derived MRP
Current Beta	11.17%	11.60%
Historical Beta	9.97%	10.33%
Current S&P Global MI Beta	10.45%	10.84%
3-yr S&LP Global MI Beta- Blume Adjusted	9.26%	9.57%
Average	10.21%	10.59%
Overall Average	10.40%	

Risk Premium Analysis

Mr. Walters conducts two Risk Premium Analyses, an equity risk premia relative to yields on 30-year Treasury bonds and an equity risk premia relative to yields on A-rated utility bonds. Bleckman, 5 TR 1316. To calculate the equity risk premium used in each of these analyses, Mr. Walters first calculates the average of the implied equity risk premium. *Id.* In his treasury bond analysis, the implied equity risk premium is calculated as the difference between average annual authorized returns and the average annual yield on the 30-year Treasury bond in each year from 1986 through June 2024. Bleckman, 5 TR 1316-1317. Using the utility bonds, the implied equity risk premium is the difference between the authorized ROEs and the yields on A-rated utility bonds in each year over the same time frame. Bleckman, 5 TR 1317. The implied risk premia used in both of his analyses are then estimated by taking an average of the risk premia over Treasury bonds and A-rated utility bonds, respectively. *Id.* The resulting risk premia used in Mr. Walters' analyses are 5.70% (Treasury Bond Approach) and 4.34% (Utility Bond Approach).

Id. Mr. Walters applies the above referenced risk premia to estimate the cost of equity in five scenarios:

- projected treasury bond yields (10.00%);
- 13-week average risk premium on A-rated utility bonds (9.96%);
- 13-week average risk premium on Baa-rated utility bonds (10.18%);
- 26-week average risk premium on A-rated utility bonds (9.98%); and
- 26-week average risk premium on Baa-rated utility bonds (10.20%). *Id.*

Mr. Walters develops but does not rely on the five-year and 10-year rolling average bond yield risk premium estimates. Bleckman, 5 TR 1318. Had he relied on this data, the results of his analyses would have increased. *Id.* If he had relied upon the five-year rolling average data developed in his exhibits, and as shown in Exhibit A-221 (MRB-30), the range of results of his analyses utility bond yield risk premium would have increased to 10.01% to 10.25%. Bleckman, 5 TR 1320. Mr. Walters assumes a Treasury bond yield of 4.30%. *Id.* Adding the five-year rolling average treasury bond risk premium of 5.73% to his projected Treasury bond yield would result in an ROE estimate of 10.03%. *Id.*

DCF Analysis

Mr. Walters performs a constant growth and multi-stage DCF analysis. Bleckman, 5 TR 1293. His constant growth DCF analysis relies on the two following things: (1) a 13-week average of the high and low stock prices of the utilities in his proxy group; (2) the average of analysts' earnings growth estimates as reported by Zacks, S&P Capital IQ Market Intelligence, and Yahoo!Finance as of August 9, 2024. *Id.* The mean and median results of Mr. Walters' constant growth DCF models are 11.34% and 10.99%, respectively. *Id.*

Mr. Walters also performed a sustainable growth rate DCF model which relies on the following things: (1) the same prices as used in his constant growth DCF analysis; and (2) an

estimate of a long-term sustainable growth rate based on the market-to-book ratios of the proxy group companies and projections of three- to five-year projections of earnings, dividends, earned book equity returns, and stock prices, as reported by Value Line. *Id.* The mean and median results of this DCF model were 9.20% and 8.90%, respectively. *Id.*

Finally, Mr. Walters conducts a multi-stage DCF which relies on (1) the same price data used in the constant growth DCF model, (2) projected EPS growth rates used in his constant growth DCF model for the first five-year period, and (3) a long-term growth rate of 4.24% that is relied on beginning in year 10 of his model. The transition between short- and long-term growth rates is linear. Bleckman, 5 TR 1294.

Mr. Walters' sustainable growth DCF model and multi-stage DCF model are not reasonable. Mr. Walters' sustainable growth rate DCF result suggests that it would be appropriate to significantly decrease the Company's ROE at a time when the analytical results produced by Mr. Megginson for Staff have increased considerably since the Company's last rate proceeding. Bleckman, 5 TR 1297-1298. Mr. Megginson's DCF results increased by more than 100 basis points since the Company's last proceeding. Bleckman, 5 TR 1298. Further, the average authorized ROEs have increased and the overall average from his methodologies has increased. *Id.* In sum, the results of Mr. Walters' sustainable growth rate DCF and multi-stage DCF analyses are outside the mainstream as demonstrated both by recently authorized ROEs and the model results presented by the witnesses in this proceeding. *Id.*

The assumptions Mr. Walters establishes in his sustainable growth rate DCF analysis and his multi-stage DCF analysis are flawed. As pointed out by Mr. Bleckman, the use of the sustainable growth rate in the DCF suggests there is a positive relationship between future earnings and the retention ratio; however, this assumption that future earnings growth is inversely related

to the dividend payout ratio does not necessarily hold in practice, and academic research has found the opposite to be true (i.e. there is a negative relationship between earnings growth rates and payout ratios). *Id.* Management may decide to (i) conserve cash for capital investments; (ii) manage the dividend payout for the purpose of minimizing future dividend reductions; (iii) manage its capital structure; or (iv) signal future earnings prospects. *Id.* These decisions can and do influence the dividend payout (and therefore earnings retention) in the near-term, and such decisions have been seen recently in the market. *Id.* For example, as a result of the economic effects of COVID-19, more than 40 S&P 500 companies temporarily suspended their dividends. Bleckman, 5 TR 1298-1299. Counter to Mr. Walters' 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 (and vice versa). Bleckman, 5 TR 1299. Since the payout ratio is the inverse of the retention ratio, the Authors, who were cited by Mr. Bleckman, found that future earnings growth is negatively related to the retention ratio. All three studies found that there is a negative, not a positive, relationship between earnings growth rates and retention ratios. For all of these reasons, Mr. Walters' reliance on sustainable growth rates in the constant growth DCF model is not appropriate, and therefore the Commission should not rely on the results of Mr. Walters' constant growth DCF model. Bleckman, 5 TR 1300.

Mr. Walters contends that it is necessary to consider a multi-stage DCF model to estimate the cost of equity for the Company; however, the utility industry is mature due to its relatively stable demand and historical regulatory status. *Id.* Therefore, financial projections are likely to be stable over the long-term, which supports the use of a constant growth DCF model. *Id.*

Further, Mr. Walters historically relied on the constant growth DCF model. *Id.* Mr. Walters' current position, to give substantially greater weight to the sustainable growth and

multi-stage DCF models is a recent change in his methodology. *Id.* Over time, as the constant growth DCF results have increased, Mr. Walters has gone from primary weight on that model to generally placing weight on all three models, to his current position, where he gives primary weight to the sustainable growth and multi-stage DCF models. *Id.* Mr. Walters states that he supports placing less weight on his constant growth DCF that relies on analysts' projected EPS growth rates because the average projected EPS growth rate exceeds his projected gross domestic product ("GDP") growth rate. However, this logic is entirely dependent on the assumption that the projected GDP growth rate that he develops is reasonable and appropriate. *Id.*

Mr. Walters relies on a projection from the Blue Chip Financial Forecast of U.S. nominal GDP growth over the next five to 10 years of approximately 4.24%. Bleckman, 5 TR 1301. Mr. Walters applies this growth rate in a multi-stage DCF model beginning in year 11 and holds that growth rate in perpetuity. *Id.* However, the Blue Chip Financial Forecast projection is not a projection of economic growth beginning in 11 years and therefore should not be considered a proxy for growth in perpetuity. *Id.* Mr. Walters relies on a quote from the Ibbotson SBBI 2013 Valuation Yearbook to assert his position that long-term growth must be limited by GDP growth. *Id.* However, Mr. Walters omits a portion of the discussion, which demonstrates that his assumed long-term growth rate is inconsistent with the approach recommended by Ibbotson for establishing a long-term growth rate. *Id.* As Mr. Bleckman correctly pointed out, the Ibbotson recommends that the long-term growth rate reflect the sum of the long-term historical average real GDP growth rate and the expected inflation rate. Bleckman, 5 TR 1302. As shown in Exhibit A-214 (MRB-23), relying on the historical average growth rate in real GDP and the average of the inflation estimates provided in Table CCW-7 of Mr. Walters' testimony, a reasonable estimate of nominal GDP growth would be 5.44%. *Id.* Updating Mr. Walters' multi-stage DCF analysis for a GDP growth

rate that is consistent with the Ibbotson methodology results in a cost of equity of 10.22%. Bleckman, 5 TR 1303.

As shown in Figure 10 of Mr. Bleckman's rebuttal testimony, as reproduced here, Mr. Bleckman updated Mr. Walters' analyses to reflect the aforementioned review of his analyses. 5 TR 1323. Specifically, Mr. Bleckman excluded the results of his sustainable growth rate DCF model and his Kroll MRP for the reasons discussed previously. *Id.* In addition, Mr. Bleckman updated his multi-stage DCF analysis to reflect a long-term growth rate that is developed consistent with the Ibbotson reference book that he relied upon for his GDP growth rate. *Id.* Finally, Mr. Bleckman considered the five-year rolling average risk premia that Mr. Walters developed but did not apply in his bond yield risk premium analysis. 5 TR 1323-1324. Weighing the results of the DCF, CAPM, and Risk Premium equally results in a mean and median cost of equity of 10.41% and 10.47%, respectively. *Id.*

Figure 2: Results of Mr. Walters' As-Filed and Adjusted Cost of Equity Analyses

	Mr. Walters As Filed		Mr. Walters As Adjusted	
DCF	Mean	Median	Mean	Median
Constant Growth EPS Growth Rate	10.99%	11.34%	10.99%	11.34%
Constant Growth Sustainable Growth Rate	8.90%	9.20%	NM	NM
Multi-Stage DCF	9.29%	9.31%	10.22%	10.26%
Average DCF	**9.73%**	**9.95%**	**10.61%**	**10.80%**
CAPM				
Kroll Historical MRP				
Current VL Beta	9.30%		N/M	
Historical VL Beta	8.47%		N/M	
Current S&P Beta	8.80%		N/M	
3-yr Beta	8.30%		N/M	
Risk Premium Method				
Current VL Beta	11.17%		11.17%	
Historical VL Beta	9.97%		9.97%	
Current S&P Beta	10.45%		10.45%	
3-yr Beta	9.72%		9.72%	
FERC MRP				
Current VL Beta	11.60%		11.60%	
Historical VL Beta	10.33%		10.33%	
Current S&P Beta	10.84%		10.84%	
3-yr Beta	10.06%		10.06%	
Average CAPM	**9.92%**		**10.52%**	
Risk Premium				
Projected Treasury Yield	10.00%		10.03%	
13-week Yields				
A-Rated Utilty Bond	9.96%		10.01%	
Baa-Rated Utilty Bond	10.18%		10.23%	
26-week Yields				
A-Rated Utilty Bond	9.98%		10.03%	
Baa-Rated Utilty Bond	10.20%		10.25%	
Average Risk Premium	**10.06%**		**10.11%**	
Average of methodologies (mean DCF)			**10.41%**	
Average of methodologies (median DCF)			**10.47%**	

c) MNSC's CAPM Analysis is Irredeemable; However, by Adding Valid and Proper Adjustment to MNSC's DCF Analysis, MNSC's Ultimate Analysis Supports the Company's Requested ROE

Mr. Bandyk presented a CAPM analysis and a DCF analysis. Mr. Bandyk's CAPM analysis relies on (1) a risk-free rate of 4.02% that is an average of three sources: Dr. Damodaran; the IESE Business School survey; and Kroll; (2) current beta for CMS Energy as published by Value Line; and (3) an estimated MRP of 4.70% that is an average of the same three sources that he used to estimate his risk-free rate. Bleckman, 5 TR 1304. Mr. Bandyk's CAPM result for CMS Energy is 8.01%. *Id.* Prior to further review, already, this is an absurdly low result and is thus questionable on its face.

In any event, first, Mr. Bandyk's CAPM result is not appropriate to rely on given the circular nature of using CMS Energy – one business and the parent of the Company no less – to set the ROE of the subject. Bleckman, 5 TR 1279. Further, the resulting return is well below any return that has been authorized for an electric utility. *Id.* For these reasons, his CAPM analysis as presented should not be relied upon in the determination of the ROE for the Company. *Id.*

To be more specific as to how Mr. Bandyk's CAPM analysis fails, the projected market risk premia that Mr. Bandyk relies on in his analysis overlooks[20] the inverse relationship between interest rates and the MRP. Bleckman, 5 TR 1312. Because current interest rates on long-term government bonds are less than the historical long-term average interest rate for those same bonds, the inverse relationship between interest rates and the MRP indicates that the MRP should be greater than, not less than, the long-term historical average of 7.17%. *Id.* However, the market

[20] For example, as noted in Mr. Bleckman's rebuttal testimony, the historical arithmetic mean MRP from 1926-2023 is 7.17%. 5 TR 1312. As also noted, the historical income-only return on government bonds used to calculate the historical MRP over that same period is 4.87%; however, Mr. Bandyk's risk-free rate on long-term government bonds is 4.02%. *Id.*

risk premia used by Mr. Bandyk of 4.70% is significantly less than the historical average MRP of 7.17%. *Id.* As a result, Mr. Bandyk has **severely** understated the MRP in his CAPM analyses, which in turn, has caused the result of Mr. Bandyk's CAPM analysis being extremely low and unreliable. *Id.*

Next, and as mentioned above, in developing his CAPM analysis, Mr. Bandyk uses a proxy group that consists of only CMS Energy, the parent company of Consumers Energy. *Id.* It is unreasonable to use a proxy group of one company in any of the cost of equity analyses. *Id.* Further, CMS Energy should not be included in a proxy group for the Company anyway due to the circularity involved in estimating the cost of equity by relying on the parent company that would be affected by the outcome of the proceeding. Bleckman, 5 TR 1312-1313. Given these substantial flaws, Mr. Bandyk's CAPM analysis should not be considered in the Commission's determination of the ROE for Consumers Energy, and therefore Mr. Bleckman also excluded the analysis from his adjusted results. *Id.*

Mr. Bandyk also presents a DCF analysis. Correcting Mr. Bandyk's DCF analysis to rely on the methodology established by the FERC, which he claims to rely on, including the use of earnings growth rates, rather than dividend growth rates and correcting the errors in his DCF analysis increase the overall result from that methodology to 10.80%. Bleckman, 5 TR 1279. In Exhibit A-215 (MRB-24), Mr. Bleckman recreated Mr. Bandyk's DCF analysis correctly[21], using the Company's expected dividend yield. Relying on the Company's current dividend yield and

[21] Mr. Bandyk cites to the FERC methodology as support for his constant growth DCF analysis; however, Mr. Bandyk's analysis is not consistent with that methodology. The FERC relies on projected EPS growth rates for its analysis, weighing that 80%, and giving 20% weight to the long-term growth rate. Mr. Bandyk's use of dividends per share growth rates is inconsistent with the FERC methodology. Bleckman, 5 TR 1297. Mr. Bandyk also did not correctly calculate the expected dividend yield in his DCF analysis. The expected dividend yield is calculated as the current dividend yield plus one year of growth. Therefore, as the growth rate changes, the expected divided yield changes. Mr. Bandyk relied on the Company's estimate of the expected dividend yield and recalculated a long-term growth rate that was not consistent with that expected yield. *Id.*

the projected EPS growth rates for the proxy group companies (as established in Mr. Walters' exhibits), Mr. Bleckman correctly adjusted the expected dividend yield by the weighted growth rate. 5 TR 1302. The weighted growth rate assigns an 80% weight to the projected EPS growth estimate and a 20% weighting to the long-term growth rate that Mr. Bandyk estimated. Bleckman, 5 TR 1303. As shown in this exhibit, updating for these two changes, increases the mean result of Mr. Bandyk's DCF analysis to 10.80%. *Id.*

Figure 3, reproduced below from Mr. Bleckman's rebuttal testimony, presents the results of Mr. Bandyk's cost of equity analyses based on the corrections identified above and as follows:

1) the correction to Mr. Bandyk's DCF model, which he suggested is based on the FERC methodology, to rely on projected EPS growth rates, consistent with that approach;
2) the correction to the dividend yield in his DCF analysis to be consistent with the weighted growth rate used in that analysis; and
3) based on the circular nature of the CAPM of CMS Energy, the exclusion of that analysis from the adjusted results.

Finally, while a flawed methodology, following Mr. Bandyk's approach of averaging the DCF result (as updated) with the Company's currently authorized ROE results in an ROE estimate of 10.35%, which ultimately demonstrates that the Company's proposed ROE is reasonable. Bleckman, 5 TR 1279, 1323.

Figure 3: Results of Mr. Bandyk's As-Filed and Adjusted Cost of Equity Analyses

	As Filed	As Adjusted
Two-Stage DCF	8.95%	10.80%
CAPM	8.01%	
Average	8.48%	10.80%
Consumers Existing ROE	9.90%	9.90%
Recommended ROE	**9.19%**	**10.35%**

Bleckman, 5 TR 1323

iii. Response in Opposition to Walmart Witness Perry's Proposed ROE

References in the Record: Bleckman, 5 TR 1287-1288

Walmart witness Perry outlines six recent rate proceedings in Michigan where the Commission has established the ROE over the period from 2022 through 2024, noting that the average of those cases was an authorized ROE of 9.89%. In addition, Ms. Perry summarized authorized ROEs for vertically integrated electric utilities in state regulatory jurisdictions nationally from 2022 through 2024. As shown in Mr. Bleckman's rebuttal testimony, Ms. Perry's statement that the Company's requested ROE is "counter to broader electric industry trends" is false. Bleckman, 5 TR 1287.

Contrary to Ms. Perry's statements, as the yields on Treasury bonds have increased, authorized ROEs have also increased. *Id.* Further, as Ms. Perry notes, Michigan's returns have historically been above the average authorized ROE. Therefore, it is reasonable to expect that as the Commission considers the changes in interest rates over time, the Company's return would follow the industry trend and would be increasing, as proposed by the Company. *Id.*

Additionally, Ms. Perry's testimony regarding the reduced risk in Michigan's regulatory framework is not complete or meaningful in the context of establishing the ROE for Consumers Energy. As noted by Mr. Bleckman, Ms. Perry does not conduct a traditional cost of capital study whereby she evaluates the investor-required return for comparable companies and compares the risks of those companies and Consumers Energy to establish the relative risk of the Company. Ms. Perry simply identifies certain aspects of Michigan regulation, specifically the use of a projected test year, CWIP in rate base, and alternative recovery mechanisms and suggests that the existence of these mechanisms is risk mitigating. *Id.* This observation is incomplete and does not result in any meaningful information that can be used to set the ROE.

In his rebuttal testimony, Mr. Bleckman describes Michigan's regulatory environment and the impact to the Company's credit quality. 5 TR 1287-1288. The return that is set in this proceeding is intended to reflect the investor-required return. 5 TR 1288. That return is based on the return that investors can achieve on investments of similar risk. *Id.* Therefore, it is insufficient to simply review the risks of the Company and make any meaningful conclusions as to the appropriate ROE that will meet these objectives. Any evaluation of risk necessarily requires that it be a comparison of the Company's risk relative to the market to determine where the Company's return should be placed in the spectrum of market returns. For example, investors may identify aspects that are risk mitigating to a greater or lesser degree of other states' regulation when compared to Michigan. *Id.* Ms. Perry's review of Michigan regulation is incomplete and cannot be used to make such an assessment. *Id.* As such, it would be reasonably disregarded in setting the ROE for Consumers Energy.

iv. Response in Opposition to MNSC Witness Denzler's Proposed Reduction in the Company's ROE

References in the Record: Bleckman, 5 TR 1288-1289

On page 51 of his direct testimony, MNSC witness Denzler states that if the Commission were to approve the Company's Service Restoration Cost Sharing Mechanism ("SRCSM" or "Cost Sharing Mechanism"), that the Commission should then also reduce the Company's authorized ROE. Mr. Denzler does not conduct a traditional cost of capital study, evaluating the investor-required return for comparable companies and compares the risks of those companies and Consumers Energy to establish the relative risk of the Company. Mr. Denzler simply identifies the Company's proposed SRCSM and suggests that the approval of this mechanism would be risk mitigating. Mr. Denzler fails to note that the Company's proposed mechanism tracks only 50% of actual costs compared to approved rate levels so it does not fully mitigate the Company's storm

risk. Bleckman, 5 TR 1288. Additionally, he fails to note that the proposed mechanism is symmetrical. *Id.* His observation is incomplete and does not result in any meaningful information that can be used to set the ROE.

While rating agencies and investors view regulatory recovery mechanisms as constructive, they expect reasonable regulatory decisions with respect to the Company's ROE. Bleckman, 5 TR 1289. The authorized ROE is a key signal provided by a utility commission and that the authorized ROE will be a major determinant in their perception of the Michigan regulatory environment, investment in Consumers Energy, and in the state of Michigan more broadly. *Id.* An authorized ROE of 10.25% is reasonable given the risk profile for the Company. Mr. Denzler's recommendation to reduce the Company's ROE in the event of an approved SRCSM, therefore, should be rejected.

4. <u>ROE Conclusion and Request for Relief</u>

It is not safe to presume, as Staff, the Attorney General, ABATE, MNSC, Walmart, UCC, and CEO apparently have, that lowering Consumers Energy's authorized ROE would not increase risk when it comes to the Company's critical financing. Additionally, there already exists significant risk whether Michigan will continue to be viewed in the eyes of potential investors as having a constructive regulatory framework. If, despite the lack of supportive evidence, the Commission were to adopt the proposals of Staff, the Attorney General, ABATE, MNSC, Walmart, UCC, and CEO on the Company's ROE, it could result in undoing the very constructive regulatory environment that has facilitated Consumers Energy's successful capital attraction activities for the benefit of customers over the past several years. The Commission should reject these parties' attempts to squander the long-developed financial strength of the Company.

A return of 10.25% as requested by the Company is within the range of reasonable returns for both investors and customers, and adopting a 10.25% return in this case will help protect the

Company's credit and assure that Consumers Energy continues to have reasonable access to capital when needed on reasonable terms and conditions, thus satisfying criteria required under the Fourteenth Amendment pursuant to the *Hope* and *Bluefield* precedents.

Authorizing an ROE in this case of 10.25% 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 6.17%. The calculation of the 6.17% overall rate of return is shown in Appendix D to this Initial Brief, page 1. Exhibit A-210 (MRB-19).

5. Long-Term Debt Cost

References in the Record: Bleckman, 5 TR 1207-1208, Exhibits A-14 (MRB-1), Schedule D-1 and A-14 (MRB-4), Schedule D-2; Megginson, Exhibit S-4, Schedule D-1; Coppola, Exhibit AG-1.17

The Company proposed a long-term debt cost rate of 4.35% in this case. Consistent with past Commission practice, the costs are determined on a net proceeds basis. 5 TR 1207. The long-term debt cost rate was calculated starting with the debt issuances outstanding as of December 31, 2023, adding the new debt issuances in January 2024, and adding the planned new debt issuances in August 2024, May 2025, and August 2025. *Id.* The new debt issuances are shown on Exhibit A-14 (MRB-4), Schedule D-2, lines 42 through 45. See also Exhibit A-14 (MRB-1), Schedule D-1, line 2, column (e). The Company also assumed a spread of 138 basis points over the United States Treasury rate. 5 TR 1208. The Commission should accept the Company's proposals. Staff utilized a 4.25% cost rate for the Company's long-term debt, and the Attorney General utilized a 4.26% cost rate for the Company's long-term debt (see Exhibit S-4, Schedule D-1, line 1, column (e); Exhibit AG-1.17, line 1, column (e)).

Concerns with Staff's Proposal

Mr. Bleckman had a number of concerns with Staff's cost rate for the Company's long-term debt. First, on line 41 of his Exhibit S-4, Schedule D-2 (Staff's long-term debt balance and cost

rate projection), Mr. Megginson includes a projected $665 million long-term debt issuance in August 2024 with a projected interest rate of 5.20%. 5 TR 1242. In August 2024, the Company issued $700 million of long-term debt with a 4.70% interest rate. *Id.* Mr. Bleckman pointed out that Mr. Megginson's projected cost of long-term debt should therefore be updated to reflect this actual debt issuance. 5 TR 1242-1243. Second, Mr. Bleckman identified that current projections for the 30-year U.S. Treasury rate, which serve as the basis for the Company's forecasted debt issuances in 2025, are higher than Mr. Megginson used in developing his cost of long-term debt projections. 5 TR 1243. On his Exhibit S-4, Schedule D-2, Mr. Megginson projected a 30-year bond yield of 3.64% in 2025. According to Bloomberg, the projected 30-year bond yield is 4.10% for 2025. *Id.* Finally, Mr. Megginson's assumed credit spread (added to the U.S. Treasury rate to calculate the total projected interest rate on the new debt issuances) is also unreasonably low. *Id.* In calculating his projected cost of long-term debt, Mr. Megginson averaged the 30-year bond yield projection from S&P Global Market Intelligence with a projection from econforecasting.com. *Id.* First, as Mr. Bleckman identified, this is a departure from Mr. Megginson's data source used in the Company's last electric rate case (Case No. U-21389) and previous rate cases in which Blue Chip Financial Forecasts was used. *Id.* Mr. Megginson provided no basis or explanation for his change in data source and why this is now his preferred method. Second, as Mr. Bleckman identified, the 30-year treasury rate projections from econforecasting.com are significantly lower than that of S&P Global Market Intelligence (Mr. Megginson's other data source). *Id.* According to Mr. Megginson's Exhibit S-4, Schedule D-2, the projected 30-year U.S. Treasury rate for 2024 was 58 basis points lower than those projected by S&P Global Market Intelligence and 64 basis points lower for 2025. Mr. Bleckman considers this a significant variance that calls into question the validity of econforecasting.com as

a data source. *Id.* Finally, the Company is not aware of econforecasting.com being used as a data source for U.S. Treasury rate projections by any other intervenors in the Company's previous rate cases or of examples of other jurisdictions in which it was used. 5 TR 1243-1244. In its discovery response included in Exhibit A-226 (MRB-35), Staff confirms that they are also unaware of any other regulatory commissions that have relied on econforecasting.com. 5 TR 1244. Conversely, the Company's source for U.S. Treasury rate projections, Bloomberg, is a globally recognized and extensively used source for interest rate forecasts and therefore should be the preferred method in developing the cost of long-term debt in this case. *Id.*

Mr. Megginson's use of the credit spreads on the Company's recent long-term debt issuances as a basis for projecting a 105 basis point credit spread on the Company's forecasted debt issuances through the test year in this case is not a reasonable approach. *Id.* As Mr. Bleckman explained on page 31 of his direct testimony, credit spreads for long-term debt issuances are very difficult to predict and can be quite volatile in short periods of time. This is because credit spreads are based on a number of factors, most notably the Company's credit rating and the market conditions at the time of the debt issuance, including both same-day and short-term supply/demand dynamics. *Id.*

Mr. Bleckman commented that the 105 basis point credit spread that Mr. Megginson used is also quite obviously at the very low end of the historical spreads for 30-year debt issuances, as evidenced in the chart on page 28 of his rebuttal testimony. In addition, as shown in Staff's discovery response included as Exhibit A-206 (MRB-15), Mr. Megginson uses credit spreads on the Company's recent long-term debt issuances which are not 30-year maturities as a basis for projecting the credit spreads on forecasted debt issuances that are assumed to be 30-year maturities.

For the above stated reasons, Mr. Megginson's methodology for estimating the credit spread on the Company's projected long-term debt issuances is faulty and should be rejected by the Commission. Alternatively, the Company has provided a very sound approach to projecting credit spreads. 5 TR 1245. Given the lack of a reliable source for projected credit spreads, Mr. Bleckman applied the calculated average credit spread on a 30-year debt issuance for investment grade utilities from the last 15 years which was approximately 138 basis points. *Id.* Since credit spreads can be volatile in the short-term, a longer-term historical average is a rational approach with regard to credit spreads. *Id.* In addition, credit spreads on debt issuances vary based on the tenure or maturity of the debt issuance (for example, a 10-year bond versus a 30-year bond). *Id.*

The impact to Staff's projected cost of long-term debt adjusted for these items identified in Mr. Bleckman's rebuttal testimony is shown on Exhibit A-209 (MRB-18), which shows Staff's cost of long-term debt calculation adjusted for the Company's actual August 2024 long-term debt issuance, current U.S. Treasury rate projections for the Company's 2025 projected issuances, and the projected credit spread on the Company's 2025 long-term debt issuances of 138 basis points. *Id.* The result is an increase to Staff's projected cost of long-term debt from 4.25% to 4.27%. *Id.*

Concerns with the Attorney General's Proposal

Starting on page 90 of his direct testimony, Mr. Coppola recommends that the Company's cost of long-term debt be lowered from 4.35% to 4.26%. Mr. Coppola states that his lower cost of long-term debt incorporates the Company's actual long-term debt issuance in August 2024 as well as a lower projected 30-year U.S. Treasury rate than assumed by the Company.

As covered in Mr. Bleckman's rebuttal testimony, and as described above to in reference to Mr. Megginson's proposal, and Exhibit A-209 (MRB-18), while it is appropriate to adjust the

Company's projected cost of long-term debt for the August 2024 debt issuance and for current U.S. Treasury rate projections, the resulting adjusted cost of long-term debt is 4.27%. 5 TR 1266. It is important to note, however, that the latest interest rate projections should not be incorporated into intervenor positions only when they are lower than as originally filed. *Id.* The adjusted cost of long-term debt projection is reflected in Exhibit A-210 (MRB-19) – the Company's Revision to Staff's Exhibit S-4, Schedule D-1. *Id.*

6. Short-Term Debt Cost

References in the Record: Bleckman, 5 TR 1210, Exhibit A-14 (MRB-5), Schedule D-3; Megginson, Exhibit S-4, Schedule D-1; Coppola, Exhibit AG-1.17

The Company originally proposed a short-term debt cost rate of 4.97% for the test year. The Company calculated its short-term debt cost rate by dividing the total cost of the two components of short-term debt (i.e. the costs related to: (i) its short-term liquidity facilities, and (ii) its renewable liabilities program) by the total outstanding balance projected for the two components. Bleckman, 5 TR 1210; Exhibit A-14 (MRB-5), Schedule D-3, page 1. Staff recommended a cost of short-term debt of 4.09%, and the Attorney General recommended a cost of short-term debt of 4.28%, as reflected in Staff's Exhibit S-4, Schedule D-1, line 10, column (e), and the Attorney General's Exhibit AG-1.17, line 5, column (e).

Concerns with Staff's Proposal

Mr. Bleckman points out that Staff's projected cost of short-term debt of 4.09% is understated. 5 TR 1246. One of the components of the Company's projected short-term debt balance is short term debt – renewable liability. *Id.* The cost rate applied to the renewable liability is based on the projected short-term borrowing rate available to the Company. *Id.* This is explained on page 34 of Mr. Bleckman's direct testimony:

> Section 21(4) of Public Act 295 of 2008 discusses the cost rate for the renewable liability, and it provides for "the creation of a

> regulatory liability that accrues interest at the average short-term borrowing rate available to the electric provider during the appropriate period."

Mr. Megginson applies a 1.00% cost rate to the Company's projected short-term debt – renewables liability balance. This projected interest rate is significantly understated. *Id.* Instead of using the same interest rate applied to the Company's projected short-term debt – short-term liquidity facilities (commercial paper) balance, Mr. Megginson uses the short-term interest rate from Case No. U-21197, the Company's renewable energy cost reconciliation case for 2021 of 1.00%. There have been dramatic changes in short-term interest rate projections since Case No. U-21197 was filed in August 2022. 5 TR 1246. The short-term rate applied to the renewable liability balance reflects the prevailing average short-term rate available to the Company rather than being locked in at any historical projection. 5 TR 1246. For example, in 2024, the short-term rate applied to the renewable liability balance has been approximately 5.2%, 420 basis points higher than the 1.00% that Mr. Megginson proposes. 5 TR 1246.

Mr. Megginson's assumed interest rate from 2021 is clearly in contradiction with the "short-term borrowing rate available to the electric provider during the appropriate period" as required by PA 295. 5 TR 1247. Consequently, the 1.00% interest rate projection from that case is not appropriate to be used for the test year in the current case. 5 TR 1247. For these reasons, Staff's lower projected cost of short-term debt should be rejected.

Response to the Attorney General's Proposal

While the Company disagrees with Staff's use of a 1.00% interest rate applied to its projected renewable liability balance, it's appropriate to revise the Company's projected cost of short-term debt to account for more recent interest rate projections from Bloomberg. 5 TR 1246.

Mr. Coppola recommends a cost of short-term debt of 4.28% based on more recent interest rate projections from Bloomberg as reflected on his Exhibit AG-1.16. The Company does not

object to this cost of short-term debt projection. This is shown on Exhibit A-210 (MRB-19), the Company's updated capital structure for the test year ending February 28, 2026.

D. Overall Rate of Return

References in the Record: Bleckman, Exhibit A-210 (MRB-19)

Using an ROE of 10.25% 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 6.17%. The capital structure, cost rates, and calculation of these returns are shown in Exhibit A-210 (MRB-19), and reproduced in Appendix D, page 1, to this Initial Brief. Consumers Energy requests the Commission adopt the capital structure and cost rates as shown in Appendix D, page 1, to this Initial Brief.

V. ADJUSTED NET OPERATING INCOME

A. Jurisdictional Revenues and Sales Forecast

1. Sales Forecast

References in the Record: Breuring, 5 TR 1563-1568, 1578, 1584-1588, Exhibits A-15 (EMB-2), Schedule E-1, A-15 (EMB-3), Schedule E-2, A-15 (EMB-5), Schedule E-4; Kelly, 5 TR 1023-1024

Company witness Eugène M.J.A. Breuring projected Company jurisdictional electric deliveries of 33,704 GWh for the test year ending on February 28, 2026. Exhibit A-15 (EMB-3), Schedule E-2. Mr. Breuring described, in detail, the method he used to arrive at this amount. 5 TR 1563-1564. Key variables affecting the Company's forecasts are weather, the economy, and demographics. Kelly, 5 TR 1023-1024. Mr. Breuring used the 15-year average of Heating Degree Days and Cooling Degree Days to capture the seasonal weather variation in deliveries and demand across the year. 5 TR 1567. He used S&P Global's (formerly, IHS Markit) employment, industrial, and population forecasts to project economic and demographic changes in his forecast.

5 TR 1568. He included full-service and choice customers in the forecast. Exhibit A-15 (EMB-2), Schedule E-1.

Mr. Breuring also forecasted the Company's test year generation requirements of 38,757 GWh after accounting for a line-loss factor. Exhibit A-15 (EMB-2), Schedule E-1; Exhibit A-15 (EMB-5), Schedule E-4. "The forecasted total electric deliveries are increased by a line loss factor as determined by the 2022 System Loss Study to arrive at the Company's total generation requirements, i.e. system output . . . ." 5 TR 1578. The Company's forecast reflects its DPP programs, EWR programs, CVR, and Residential Summer On-Peak ("RSP") rate.

- Mr. Breuring reduced the peak demand forecast for the test year by approximately 34 MW to account for the Company's DPP programs (i.e. its PTRs and CPP programs) from 2023 to 2027.
- He reduced peak demand by 823 MW for EWR and 51 MW for CVR measures.
- He reduced peak demand by approximately 108 MW for Rate RSP. 5 TR 1579.

Test year deliveries are projected at 36,395 GWh, see Exhibit A-15 (EMB-2), Schedule E-1, which are forecasted using a two-year Compound Annual Growth Rate ("CAGR") of -0.5% over the 2023 historical year deliveries of 36,791 GWh. See Exhibit A-5 (EMB-1), Schedule E-1. Of this change, 1.2% is attributable to the Long-Term Industrial Load Retention Rate ("LTILRR"). Excluding LTILRR, the two-year CAGR is -0.5%. 5 TR 1573. The historic annual, class-level data for 2019–2023 are included in Exhibit A-5 (EMB-1), Schedule E-1, and the projected annual class level data for 2024–2028 appear in Exhibit A-15 (EMB-2), Schedule E-1.

Staff recommended an adjustment to the Company's test year projected deliveries (a 338,681 MWh increase) using a novel and simplistic approach based exclusively on the most recent 12 months. 5 TR 3739-3746. As Mr. Breuring explained, Staff took a single point in time, the most recent 12 months, to calculate residential customer use and then offset it with EWR savings to arrive at a test year figure. Staff then multiplied the projected use by the Company's

projected customer count. 5 TR 1584. Similarly, for commercial deliveries, Staff began with a single data point (the last 12 months) and applied a two-year CAGR to arrive at its forecast. 5 TR 1585. These are not valid forecasting methods for several reasons.

First, Staff's forecasts assume that the future will be identical – except for an EWR adjustment – to a single historical year. Staff applied a simple formula to the 2023 historical results without considering new econometric data and without any information whatsoever about forecasted conditions that would explain the need for Staff's adjustments. The Company's forecast, by contrast, used proven, long-standing regression modeling to develop a robust forecast. The modeling incorporates several years of historical data and coefficients that account for different customer behavior in different circumstances.

Second, whereas Staff did not test its forecasts, the Company used separate, elaborate regression models that are specific to each customer class – as each customer class behaves differently in response to economic, weather, and other variables – to test its forecasts. 5 TR 1585. As Company witness Breuring explained, each regression model is "evaluated by using the adjusted coefficient of multiple determination ("*R*") and Mean Absolute Percent Error ("MAPE"). These evaluation measures indicate how well models perform in the forecast periods." 5 TR 1586.

The Company's test revealed that the residential usage regression model has a very high *R* value of 97.4% and a very low error percentage, or MAPE, of 1.74%, while its commercial customer count regression model similarly has a high *R* of 96.2% and a low error percentage of 0.3%. 5 TR 1586. The regression modeling process is robust. By including a larger number of observations over an extended period (e.g. 160 months for the residential regression model), the Company's regression models avoid placing too much weight on any single factor or snapshot in time. Staff, by contrast, focuses exclusively on a single period (the most recent 12 months).

Models forecast future load better when they incorporate many observations. For example, the post-pandemic work environment is continuing to trend away from work from home and trend toward returning to office settings. This trend puts increased downward pressure on residential electric load. A modeling approach, like Staff's approach, that does not capture behavioral trends like this, up or down, is less reliable.

Besides these flaws, several Staff adjustments were completely unsupported. For example, although Staff explained its adjustments to residential and commercial deliveries, it did not explain its adjustments to industrial, self-generation, and Grand Rapids streetlighting deliveries. 5 TR 1584. Moreover, Grand Rapids Streetlighting is included in miscellaneous revenues and should not be part of this analysis at all, reducing Staff's delivery forecast by 16,385 MWh. 5 TR 1589.

Staff's testimony is also internally inconsistent. Staff witness Paul R. Ausum recommended adding a total of 338,681 MWh to the Company's projected deliveries, but Staff witness Isakson (Staff's pricing witness) did not capture the full adjustment. Rather, Mr. Isakson adjusted only for the residential and commercial customer classes, 5 TR 1588, and even these adjustments were not consistent with Mr. Ausum's adjustments for these classes.

Mr. Isakson used Mr. Ausum's adjusted cycle-billed residential deliveries and adjusted cycle-billed commercial deliveries without regard for the unbilled factor that Mr. Ausum proposed in his projections. This means that Mr. Isakson overstated the adjustments by 32,027 MWh, overstating Staff's present revenues and understating Staff's deficiency. 5 TR 1588.

The Commission should reject Staff's adjustments and adopt the Company's sales forecast as proposed.

2. Total Electric Operating Revenues

References in the Record: Breuring, 5 TR 1568, 1570, 1589-1591, Exhibit A-15 (EMB-3), Schedule E-2; Isakson, 5 TR 3606

Mr. Breuring also projected that the Company's total electric jurisdictional operating revenues will be $4.933 billion in the test year. Exhibit A-15 (EMB-3), Schedule E-2, line 22, column (j). This includes base tariff revenues, PSCR revenues, and miscellaneous revenues. Exhibit A-15 (EMB-3), Schedule E-2, summarizes the component differences between the 2023 historic revenues and deliveries and the projected test year revenues and deliveries used in this case. 5 TR 1568.

The Company's projected base tariff revenues are offset by the Residential Senior Citizen ("RSC"), Residential Income-Assistance ("RIA"), and Low-Income Assistance ("LIA") credits, 5 TR 1570, which are embedded in the base tariff amount. 5 TR 1570; Exhibit A-15 (EMB-3), Schedule E-2, line 1, column (j). Customers qualify for the RIA and LIA credits if they participate in certain Michigan Department of Health and Human Services ("MDHHS") programs. 5 TR 1591.

Based on these customer counts, the RSC customer credits offset $16.8 million (350,683 customers x $4 credit x 12 months) in revenue in the projected test year, while the RIA credits offset approximately $6.4 million (66,555 customers x $8 credit x 12 months) and the LIA credits approximately $1.5 million (4,200 LIA customers x $30 credit x 12 months). 5 TR 1570.

Staff challenged the Company's RSC and RIA customer counts, proposing a reduction to the RSC count based on a three-year average that has not been used before and a reduction to the RIA count that is not supported by evidence about the customers' disposable income. Staff's arguments should be rejected.

a. RSC Count

To the Company's knowledge, the Commission has never before adjusted the Company's senior citizen count – used to set its projected RSC credits – based on a three-year average. Mr. Isakson, however, relies on a three-year average to recommend reducing the Company's RSC count for the projected test year. According to Mr. Isakson, "Staff's method of using the historic 3-year average of customer count has been approved by the Commission in the Company's recent rate case as well as for other Michigan utilities." 5 TR 3606. But the orders Staff cites were related to RIA credits only, not the "residential credit" as a whole that would have included RSC credits. Because the orders did not apply to RSC credits, it is not accurate to say that the Commission has approved a three-year average to calculate this particular credit. 5 TR 1589-1590.

Using a three-year average makes less sense when estimating the senior citizen population than it does for the RIA counts since the senior citizen population does not fluctuate like the low-income population. As Mr. Breuring explained, "The senior citizen count is mainly dependent on the age of the customer to qualify for the RSC credit. It does not depend on customers qualifying for other specific programs, as is the case with the income-assistance credit." 5 TR 1590. Plus, the current trajectory of senior citizens within the Company's service territory is consistently growing and, barring extreme circumstances, there is no reason to expect a significant drop.

Despite the recent growth to the RSC count, the Company's count for the test year is 6%, or 23,000, below current actuals. Mr. Isakson predicts this number will drop even further by 11%, or 42,000, below current levels. This is unlikely to happen to say the least. The Company has only experienced such a significant decline in senior citizen customers during the COVID-19 pandemic. 5 TR 1590. There is no reason to anticipate another global health crisis by the end of the test year.

b. RIA Count

Mr. Isakson recommended reducing the Company-projected test year RIA count of 66,555 to 61,816. As the income-assistance customer count is dependent on certain MDHHS programs, the three-year average is closer (compared to Staff's RSC count) to the Company's predicted total of 66,555 when incorporating the latest actual figures available from June 2024. But the RIA count is primarily driven by residential income levels and need, and the Company is not projecting a significant reduction in customers' need, which would require a forecasted increase in disposable income. As Staff has not introduced evidence that disposable income for RIA-qualifying customers will increase by more than 5% as it projects, there is no sound basis to reduce the number of RIA customers.[22]

B. Fuel, Purchased, and Interchange Power Expense

References in the Record: Metz, 5 TR 2301-2313, Exhibits A-140 (MLM-1), and A-58 (EMB-6)

Company witness Megan L. Metz, Director of Electric Supply Operations and Power Supply Cost Recovery, testified concerning the Company's projected fuel, purchased, and interchanged power expense. 5 TR 2302-2313. The Company projected power expenses using the Aurora Production Costing Program, which was the same platform the Company used in its 2021 IRP, Case No. U-21090, to simulate the electric generation and transmission market system. 5 TR 2305. The Company is forecasting $1.164 billion of Total Fuel, Variable Purchased, and Net Interchange expense, and $385.537 million of Total Capacity and Non-Utility Generator Fixed Costs. Exhibit A-140 (MLM-1), page 1, line 27, column (o), and line 34, column (o), respectively. These amounts, together with the test period transmission expense of $567.841 million (Exhibit

[22] As discussed in the rate design section of this brief, and as pointed out by Staff witness Isakson, the Company mistakenly transposed the RIA and RSC customer count projections when developing its rate design. This mistake was limited to the rate design and did not affect the RIA or RSC counts used to calculate total electric operating revenues.

A-140 (MLM-1), page 1, line 35); the MISO Schedule 2 (Reactive) credit of $0 (Exhibit A-140 (MLM-1), page 1, line 37); and the reagent expenses for pollution control equipment and nitrogen oxide ("NOX") allowances that are expected to be recovered as part of the Company's PSCR proceedings (Exhibit A-140 (MLM-1), page 1, lines 36 and 38 through 41) constitute the total power supply costs for the test year of $2.125 billion. Exhibit A-140 (MLM-1), page 1, line 42. The Company anticipates $77.089 million of this amount to be recovered through the LTILRR Contract, $20.188 million recovered from the LEDR, and $2.028 billion to be recovered from other full-service customers during the test year. 5 TR 2312-2313. Exhibit A-140 (MLM-1), page 1, lines 43, 44, and 45. After adding in intersystem sales revenue, the total projected power supply cost for the test year is $2.374 billion. Exhibit A-58 (EMB-6), line 4. No party contested the Company's calculation of the power supply expense.[23]

C. Other O&M Expense

1. Distribution O&M Expense

a. Electric Operations

References in the Record: Kelly, 5 TR 942-985, 1048-1053, Exhibits A-104 (MPK-12) through A-110 (MPK-18); Coppola, 5 TR 2848-2856, Exhibit AG-1.38

The projected distribution O&M expenses in Electric Operations include the test year O&M associated with the following programs: (i) O&M Associated with Construction - $0; (ii) Non-Forestry Reliability - $41.305 million; (iii) Operations, Maintenance, and Metering - $51.32 million; (iv) Service Restoration - $133.5 million; (v) Field Operations - $29.835 million;

[23] Staff Exhibit S-3, Schedule C-1, line 5, shows a $16.375 million adjustment to power supply costs. However, Staff's adjustment is related to its recommendation to increase the Company's sales forecast and does not represent a disagreement with the Company's calculation of power supply expense. Consumers Energy disagrees with Staff's adjustment to the Company's sales forecast as discussed in section V.A.1. of this Initial Brief. The Commission should reject that adjustment and use the power supply expense calculated by the Company in this case. However, if the Commission adopts Staff's sales forecast, it should adopt the power supply expense that corresponds to the sales forecast used in setting rates.

(vi) Compliance and Controls - $0; (vii) Planning and Scheduling - $0; (viii) Operations Performance - $4.773 million; (ix) Operations Management - $2.015 million; (x) Operations IT projects - $0; and (xi) Wildfire Risk Mitigation Plan - $652,000. 5 TR 942-943; Exhibit A-107 (MPK-15). Company witness Kelly testified to the details of these programs, the benefits they provide, and their projected expenses. 5 TR 942-985. Also see Sections III.A.2 and V.C.3 of this Initial Brief for discussions of the Streetlighting program and Service Restoration. The projected expenses are reasonable and should be approved by the Commission.

Mr. Coppola argued that the Company's forecasted rate of growth for staking requests is too high and recommended a $200,000 reduction to the expense. 5 TR 2848-2849. The Commission should reject this disallowance. Consumers Energy's projected 5% growth rate considers the MISS DIG 811 statewide annual growth in staking and locating ticket requests since 2017, and is in fact less than the statewide rate in five of the last seven years. See 5 TR 965, Figure 51. Locating activity reflects the overall economic situation in Michigan, and does not necessarily follow utility service territory boundaries. 5 TR 1049-1050. Consumers Energy reasonably relied on the statewide MISS DIG growth rate in developing its projection in this case.

For LVD Lines Reliability O&M, Mr. Coppola recommended reducing the total expense by $12.563 million, which is made up of the following reductions: (1) $4.85 million in pole inspections to more gradually reach a 12-year cycle, (2) $4 million in switch inspections to make the increase in inspections more gradual, (3) $1 million in Metro inspections to make the increase in inspections more gradual, and (4) $2.713 million in Grid Modernization based on using a two-year average spend plus inflation. 5 TR 2850-2852. The Commission should reject these reductions.

The LVD Lines Reliability sub-program is to fund the inspection and maintenance of LVD line assets. 5 TR 944. IEEE recommends a certain cadence for these inspections and repairs of any issues identified. 5 TR 945. The increase in the LVD Lines Reliability expense is driven by the Company's plans to align with IEEE recommendations and best practices for inspections and maintenance. This includes inspecting and replacing rejected poles on a 12-year cycle, ramping up switch inspections to help avoid outages due to equipment failure, and increasing Metro inspections to prevent catastrophic failure of assets and maintain the reliability of Metro-supplied customers. 5 TR 947. In developing the Reliability Roadmap, the Company identified the spending needed to meet IEEE standards for pole inspections, switch inspections, and Metro inspections, and projected that amount of spend in this proceeding. 5 TR 1050. Mr. Coppola's proposal to cut these inspection expenses in half will delay by at least one more year the Company's ability to perform the recommended inspections and maintenance on its LVD Lines. *Id*.

The Grid Modernization expense represents the ongoing costs for implementing the Company's Grid Modernization initiatives, including providing support for programs like line sensors and substation and circuit modernization. 5 TR 947. Line sensors remotely monitor electrical current and detect sustained, momentary, and potential faults, which improves the capability to respond quickly and reduce customer outages. 5 TR 2216. Maintenance of these types of automation devices includes monitoring this equipment to identify if it is functioning properly, investigating to determine the cause of any concerns, and repairing or replacing (in the LVD Lines Demand Failures capital sub-program) as needed. 5 TR 946. The Company's projected expenses based on the maintenance needed for these devices should be approved as more reasonable than Mr. Coppola's proposal based on a simple two-year average.

Attorney General witness Coppola also recommended a $2.2 million decrease in HVD Lines Demand O&M, arguing that the Company did not support the increase. 5 TR 2852. The Commission should reject the proposed reduction. Consumers Energy explained in discovery (provided as Exhibit AG-1.38) that the Company's exhibits mistakenly included a $2.2 million increase in test year funding intended for HVD Lines Demand O&M in HVD Lines Reliability O&M. 5 TR 1051. The Company also explained in that response that the Company is increasing HVD Lines Demand O&M because recently improved HVD lines inspection technology has resulted in the identification of more anomalies that need to be addressed in this sub-program to prevent customer outages. 5 TR 1051. This improved technology has led to a backlog of anomalies, and the proposed spending is to clear this backlog and address newly identified anomalies. *Id*. The Company fully supported the reason for the increased HVD Lines Demand spending and the Commission should approve the funding amount.

Mr. Coppola proposed to reduce HVD Substations Reliability O&M by $1.4 million because of his contention that the Company did not support an increase in this expense beyond inflation. 5 TR 2853. The Commission should reject this reduction. The Company is increasing spending in this area as part of the Company's implementation of industry best practice substation inspections and increase of maintenance in order to avoid HVD substation outages. 5 TR 1053, Exhibit A-111 (MPK-19), page 121 of 183. The average HVD substation outage resulted in 0.30 SAIDI minutes (equal to 3,110 customers experiencing a 180-minute outage) in 2023, but can also be much more impactful when they occur. 5 TR 954. Each outage avoided has a significant benefit to system reliability. Properly maintaining this equipment supports reliability, safety, and efficiency, keeping costs down and decreasing the frequency and duration of outages. 5 TR 954-

955. The Commission should approve this spending to support these inspection and maintenance efforts.

Attorney General witness Coppola also recommended reducing LVD Substations Demand expense by $5.308 million and HVD Substations Demand expense by $4.467 million based on his proposal to project the expense based on a three-year historical average adjusted for inflation. 5 TR 2855. The Commission should reject this reduction. The work identified through inspections in the LVD and HVD Substations Demand sub-programs reduces the potential for outages from unplanned events. 5 TR 960. This work includes relatively quick corrections such as lubricating bearings, realigning a switch, or adding SF6 to a gas circuit breaker, which is performed in these sub-programs. Other issues require equipment replacement and are covered under a capital program. *Id*. Performing this work in a planned manner based on inspection results is more cost effective than waiting for the unit to fail. *Id*. However, current funding levels in these sub-programs have not been sufficient to adequately perform all of the maintenance activities outlined in the Reliability Roadmap. See Exhibit AG-1.38, pages 3-4. The Company's projected spending will allow the Company to perform additional inspections and the necessary corrective maintenance activities. 4 TR 560.

Mr. Coppola recommended removal of the entire $2.517 million expense for the underground workforce, arguing that it is premature to expand the Undergrounding program and that the Company already has trained employees to perform this work. 5 TR 2856. The Commission should reject this proposed removal of funding. As discussed above, the Commission should approve the Company's projected Undergrounding capital expenditures, and for the same reason should approve this Underground Workforce expense. The Company has already started developing the Undergrounding Workforce, and a 100% disallowance of this expense as

recommended by Mr. Coppola would remove the funding for those employees already with the Company. 5 TR 1053.

The Undergrounding Workforce construction crews perform undergrounding work in subdivisions and new business services, and will work on the expansion of undergrounding work discussed above. 5 TR 980. These crews can also perform replacement of failed underground and new underground construction for LVD overhead line replacement. 5 TR 980-981. An Electric Underground Construction crew has a lower cost per hour than the traditional LVD overhead crew. 5 TR 981. The Commission should approve the projected expense to allow the Company to continue to perform the necessary Undergrounding work in a cost-effective manner.

b. <u>Electric Engineering and Support</u>

References in the Record: Kelly, 5 TR 985-998, Exhibits A-104 (MPK-12) through A-110 (MPK-18)

The distribution O&M expenses in Electric Engineering Operations include the test year O&M associated with the following programs: (i) Engineering Support - $1.274 million; (ii) Electric Distribution Management - $241,000 (iii) Electric Distribution Planning - $12.782 million; (iv) Electric Distribution Design - $4.099 million; and (v) Electric Distribution Strategy - $18.748 million. 5 TR 985; Exhibit A-108 (MPK-16). Company witness Kelly testified to the details of these programs, the benefits they provide, and the projected expenses of these programs. 4 TR 985-998. The projected expenses are reasonable and should be approved by the Commission.

2. Forestry O&M Expense

References in the Record: Bolden, 3 TR 202-204, 206, 212-214, 218-222, 232, 239-240, Exhibits A-47 (PLB-1), A-48 (PLB-2), A-50 (PLB-4), and A-51 (PLB-5); Kelly, 5 TR 876; Exhibit A-12 (MPK-1), Schedule B-5.6

Trees cause more customer outages on the LVD system than any other source and are a significant cause of customer outages on the HVD system, 3 TR 202, which is why every year the Company is progressively clearing trees from more miles of line. By 2030, the Company is on track to annually clear one-seventh of its total LVD system with higher voltages trimmed more frequently and lower voltages less frequently:

FIGURE 2
LVD CLEARING SCHEDULE FOR 7-YEAR EFFECTIVE CYCLE

Substation Voltage Class	Approximate System Miles	14% Clearing Program – miles/year cleared	Effective Cycle for Voltage Class
14.4 kV	18,000	3,600	5 years
7.2 kV	10,700	1,529	7 years
4.8 kV	32,300	3,589	9 years

3 TR 210.

For its HVD system, the Company is currently on a four-year line clearing cycle and proposes to maintain this cycle. 3 TR 204.

To move toward a seven-year effective clearing cycle on its LVD system and maintain a four-year cycle on its HVD system, the Company has been investing more in line clearing for the last several years. Company witness Pamela L. Bolden, Executive Director of Electric Operations, included a table in her testimony (Figure 4) showing the Company's recent historical increases in O&M spending on the LVD and HVD systems and the corresponding historic rise in miles cleared. 3 TR 214. Figure 4 also shows projected increases in O&M spending and corresponding projected rise in miles cleared. A partial excerpt from Figure 4 showing only spending on the LVD system illustrates how the Company has been investing more on LVD clearing for the last several years and how it has used this spending to bring more circuits on cycle:

Figure 4
LVD and HVD Clearing Ramp-up Schedule

Year	Data Type	LVD O&M Clearing Miles	Other LVD Clearing Miles	Total LVD Cycle Miles	LVD O&M Expense ($M)	LVD Capital Contractor Costs ($M)	LVD % Cycle	LVD Cycle Years	LVD Clearing Crews	LVD Clearing Crews FTEs
2015	Actual	3,633	Note[1]	3,633	$31.29	Note[1]	43%	16.1	220	440
2016	Actual	3,951	Note[1]	3,951	$41.31	Note[1]	47%	14.8	210	420
2017	Actual	3,503	425	3,928	$38.36	$2.75	47%	14.9	205	410
2018	Actual	3,218	393	3,611	$39.91	$8.24	43%	16.2	210	420
2019	Actual	3,518	334	3,852	$41.08	$5.87	46%	15.2	220	440
2020	Actual	4,211	258	4,469	$46.10	$5.67	53%	13.1	220	440
2021	Actual	5,279	252	5,531	$75.83	$5.66	66%	10.6	299	598
2022	Actual	6,388	221	6,609	$91.02	$6.71	77%	9.1	334	668
2023	Actual	6,365	168	6,533	$97.79	$5.59	75%	9.2	348	696
2024	Projected	6,760	325	7,085	$105.37	$8.43	81%	8.6	402	804
2025	Projected	7,232	325	7,557	$112.79	$8.60	87%	8.1	430	860
2026	Projected	7,449	325	7,774	$113.12	$8.86	89%	7.8	430	860
2027	Projected	7,672	325	7,997	$113.43	$9.12	92%	7.6	430	860
2028	Projected	7,932	325	8,257	$113.75	$9.39	95%	7.4	430	860
Note[1]:	Capital Contractor Costs and Miles not recorded separately by LVD and HVD in 2015 or 2016									

3 TR 214.

As this excerpt shows, increased investment has allowed the Company to move closer to a seven-year effective clearing cycle on the LVD system. In 2015, the Company's LVD effective clearing cycle rate was about 16.1 years, but by 2023, the Company had reduced the effective clearing rate to 9.2 years. 3 TR 212, 214 (Figure 4); Exhibit A-47 (PLB-1), line 36. In 2024 and beyond, the Company plans to continue reducing the cycle length until it reaches 7.4 years in 2028. Exhibit A-47 (PLB-1), line 36. As the Company moves closer to a seven-year effective cycle on its LVD system and clears more backlog miles (circuit miles that have not been cleared in many years), it anticipates its costs per mile to increase until 2025 after which the cost per mile will begin to decline. Exhibit A-47 (PLB-1), line 31.

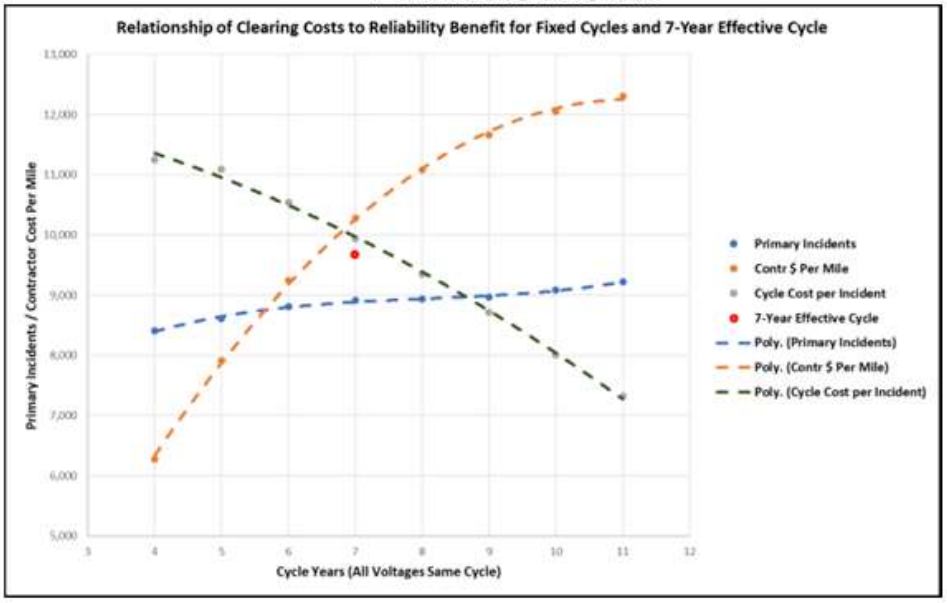
Ms. Bolden explained that "a longer clearing cycle results in more complex clearing work and requires the removal of more biomass to achieve clearance to conductors." 3 TR 232. A shorter effective cycle "equates to a reduction in the cost per mile once the cycle is achieved and circuits are cleared for the first time 'on cycle.'" 3 TR 232. At the same time, because "the LVD miles cleared required to attain this shorter cycle double from approximately 4,300 miles to

approximately 8,700 miles," the shorter cycle "drives the cost per primary incident higher" and offsets the reduction in the cost per mile. 3 TR 227.

In Exhibit A-51 (PLB-5), the Company evaluated the cost per incident reduced at various cycle lengths to determine the optimal clearing cycle for each voltage level and an optimal seven-year effective cycle across all voltages. On a five-year cycle for the Company's 14.4 kV system, a seven-year cycle for its 7.2 kV system, and a nine-year cycle for its 4.8 kV system (equating to a seven-year effective cycle), the "cost per incident reduced" is at its lowest compared to the other cycle lengths considered. Specifically, according to Ms. Bolden, "Exhibit A-51 (PLB-5), column (b), line 19, shows the cost-benefit of the seven-year effective cycle ($14,420 per reduced outage incident) to be better than a five-year cycle ($15,859 per reduced outage incident) column (b), line 21, and all other alternatives reviewed in the analysis." 3 TR 210.

Figure 3 in Ms. Bolden's testimony visually depicts the costs and benefits of a seven-year effective cycle in comparison to various fixed cycles. When comparing "contractor clearing cost per mile at various fixed cycle lengths and the fixed cycle's cost per expected primary outage incident" to the expected primary outage incident rate at these cycle lengths, the seven-year effective cycle is the optimal cycle. 3 TR 210-211. Figure 3 shows this:

FIGURE 3
FIXED CYCLE COSTS AND BENEFITS VERSUS 7-YEAR EFFECTIVE CYCLE



3 TR 211.

At approximately seven years, the contractor cost per mile intersects the cycle cost per incident. 3 TR 211. Moving to a six- or five-year cycle significantly increases the cycle cost per incident with only minimal reduction to the number of outage incidents. In short, the seven-year effective cycle delivers the most value for the dollar.

As the Company continues to increase O&M spending on its path toward a seven-year effective clearing cycle, it will further improve reliability. History and case studies bear this out. Company witness Bolden described how the number of tree-caused interruptions increased while spending was static at $40 million per year in 2014 and 2015, but the incident rate stabilized from 2016 through 2020 as the Company increased investment to $50 million. 3 TR 202. Then, after the Commission approved further investment in Case No. U-20697, the Company was able to reverse the rising incident rate altogether. According to Ms. Bolden, "As anticipated, spending approved in [MPSC] Case No. U-20697 for 2021 showed benefits beginning in 2022 when the number of outage incidents began to decrease." 3 TR 202.

The Company also performed a case study to show how increased investment in line clearing benefits customers. The Company compared outages on circuits before being cleared against outages on the same circuits after being cleared. It found that clearing vastly improved performance:

> Exhibit A-50 (PLB-4) illustrates the reduction in tree-caused primary outage incidents after clearing. For example, for the circuits cleared entirely in 2018, tree-caused primary outages decreased 74% in the year following clearing. For circuits cleared entirely in 2019, tree-caused primary outages decreased 52% the year following clearing and for circuits cleared entirely in 2020, the decrease was 38% following clearing, despite 2021's high number of MED events and two catastrophic storms. For circuits cleared entirely in 2021, tree-caused outages decreased 62% the year following clearing. [3 TR 221.]

Reliability, besides reducing outages, also cuts restoration costs. "As shown in Exhibit A-48 (PLB-2), a seven-year effective cycle on LVD would reduce an estimated 895 tree-related primary outage incidents over 2024 to 2028 and result in a potential service restoration cost avoidance of $2.371 million over the same timeframe." 3 TR 222.

Increased investment will allow the Company to eliminate, by 2030, its backlog of circuits not cleared in many years. 3 TR 219. This is exciting news for customers on these circuits because, not surprisingly, "circuits experience more tree-related outage incidents the longer it has been since line clearing was performed." 3 TR 206. And the Company's plan not only eliminates the backlog by clearing more circuits on a seven-year effective clearing cycle; it keeps the circuits on cycle. 3 TR 219, Figure 8. The Company has already made progress. In the 2021 work plan, only about 13.4% of circuit miles were cleared on a seven-year effective cycle, with approximately 86.6% of circuit miles on backlog. But in the 2022 and 2023 work plan, 32.7% and 17.8% of circuits cleared, respectively, were cleared on cycle, and the Company continued to chip away at the backlog. 3 TR 218, Figure 7.

This is progress the Company can and will build on, as Figure 8 in Ms. Bolden's testimony shows:

FIGURE 8
FORESTRY PLAN FOR BACKLOG MILES REDUCTION

Forestry Backlog Reduction Plan 2024-2030				
Year	**Plan Miles**	**On Cycle Miles**	**Backlog Miles**	**Backlog Miles Remaining**
2024	6,760	1,690	5,070	20,249
2025	7,232	2,170	5,062	15,187
2026	7,449	2,980	4,469	10,718
2027	7,672	3,836	3,836	6,882
2028	7,932	4,759	3,173	3,709
2029	8,316	5,821	2,495	1,214
2030	8,699	7,485	1,214	0

3 TR 219.

If approved, the Company also plans to target areas vulnerable to wildfires by "proposing enhanced line clearing tactics paired with imagery data and analysis for wildfire mitigation." 3 TR 239; 5 TR 876; Exhibit A-12 (MPK-1), Schedule B-5.6, line 7. In these areas with higher wildfire risk, the Company will move to a five-year cycle to better "manage growth and limit potential vegetation to conductor contact" regardless of the voltage. 3 TR 239-240. The Company will also use LiDAR imagery in these areas and use the LiDAR data collected to inform and support the Company's enhanced line clearing strategy. 3 TR 240.

a. <u>Forestry Expense</u>

References in the Record: Bolden, 5 TR 204, 203, Exhibit A-47 (PLB-1); Duell, 5 TR 3835

The Company expects to continue to invest more in line clearing and vegetation management in the 2025 calendar year, proposing $125,086,000 in O&M expenses to clear its LVD and HVD systems that year. Exhibit A-47 (PLB-1), line 24, column (m). The Company projects LVD line clearing expenses of $112,792,000 and HVD line clearing expenses of

$12,294,000 for the 2025 calendar year. Exhibit A-47 (PLB-1), lines 2 and 12, column (m). If approved, this would be the fifth year of the multi-year increases – approved in Case Nos. U-20697, U-20963, U-21224, and U-21389 – on track to an effective seven-year clearing cycle for the LVD system.[24] 3 TR 204.

The Commission should approve the Company's proposed line clearing expense. Trees and vegetation cause more customer outages on the LVD system than any other source, and clearing trees and vegetation near electric lines is the surest way to protect the system from the risk they pose. As Ms. Bolden testified, "The Company's line clearing program . . . is designed to minimize these occurrences [i.e., tree-caused outages], improve reliable service to its customers, and decrease reactive maintenance and capital expense associated with interruptions during weather events." 3 TR 203. Staff also supported the Company's proposed 2025 calendar year line clearing expense, noting, "It is crucial to allow Consumers to spend the full amount for line clearing to increase the resiliency of Consumers Energy's electric distribution system." 5 TR 3835.

The projected line-clearing costs were fully supported by Ms. Bolden's testimony and exhibits, and the Commission should approve them. The Company's proposed forestry plan will support its efforts to improve the reliability of its distribution system, directly improving the experience for the Company's customers by reducing the number and length of outages.

[24] The projected test year spending reflects operational intelligence by Forestry Operation's Department Manager, Financial Program Manager, and other staff members. 3 TR 229. The values presented in Exhibit A-47 (PLB-1) are the Forestry Operation team's projections based on historical costs per mile cleared, current system work estimates, crew availability and work schedules, and other factors to maintain clearing on the HVD system at current level and to improve the effective clearing cycle on LVD.

b. Line Clearing Within and Outside the First Zone

References in the Record: Bolden, 3 TR 241-245

In Case No. U-21389, the Commission directed the Company, in its next rate case (this case), to "provide an analysis of the feasibility of more aggressive line clearing in everything outside of the first zone in the company's next rate case." MPSC Case No. U-21389, March 1, 2024 Order, page 163. To set expectations, Ms. Bolden noted that "the Company's LVD primary clearing specification inside and outside of the first zone are the same," which can be seen in contracts with line clearing vendors. 3 TR 241. "Minimum clearance . . . is consistent across all LVD primary both inside and outside of the first zone" depending on the configuration (e.g. the minimum clearance for open-wire primary distribution is understandably different than the clearance for aerial spacer cable). So, generally, "trimming occurs between 10-15' from the conductors, while for certain weak-wooded tree species, canopy clearance is increased to 20' for all primary voltages . . . ." 3 TR 241-242.

Although clearing specification inside and outside of the first zone are technically the same, practically speaking, utilities sometimes concentrate on the first zone and early zones more than other zones because these zones reach more customers and contain fewer zone miles. 3 TR 243. As a result, more aggressive line clearing in these zones promises greater "potential reliability and overall customer benefit." 3 TR 243. As Ms. Bolden explained, "all first zones on the Company's LVD system comprise 6% of total primary miles but serve 100% of electric customers downstream of them." 3 TR 243. She included data to illustrate the point:

Figure 20

Approximate LVD Primary Zone Miles and Customers Served

Zone Number	Approximate Miles Within Zone	Approximate Miles Within and Upstream of Zone	% of Total Miles Within and Upstream of Zone	% of Total Customers Served Within and Downstream of Zone
1st	3,800	3,800	6%	100%
2nd	10,200	14,000	23%	94%
3rd	14,900	28,900	47%	70%
4th	13,800	42,700	70%	39%
5th	9,400	52,100	85%	18%
6th	5,200	57,300	94%	7%
7th	2,400	59,700	98%	3%
8th	900	60,600	99%	1%
9th+	400	61,000	100%	0%

3 TR 243.

This means that more customers benefit from enhanced clearing in the early zones than enhanced clearing in outside zones. Only when the Company enhances its line clearing practices in the early zones should it shift its focus to outside zones.

Considering this context, Ms. Bolden made several assumptions when studying more aggressive line clearing inside *and* outside the first zone:

- She assumed that "6% of tree-related outages are caused by canopy." 3 TR 242.
- She assumed that "100% of canopy-caused outages will be prevented" after the canopy is removed. 3 TR 242.
- She assumed that including canopy removal in the clearing cost per mile increases contractor costs by 35% above projected 2025 contractor cost per mile but that this increase will eventually be offset as more circuits are cleared on cycle. 3 TR 242.
- She assumed that the Company would use local workers; if out-of-state crews are needed, it would add approximately 15% to the contractor clearing costs for those crews to account for per diem expenses. 3 TR 242.

With these assumptions in mind, Ms. Bolden then outlined six more aggressive line clearing options and evaluated them according to the following six criteria: (1) estimated expense

per year over seven years; (2) projected interruptions prevented per year; (3) expense per year per interruption prevented; (4) average monthly cost per customer served over seven years; (5) percentage increase in overall LVD contractor costs; and (6) line clearing miles not completed per year without incremental funding:

Figure 21

Options of More Aggressive Line Clearing by Zone(s) and Phase(s)

Option	Targeted Zone(s)	Targeted Phase(s)	Estimated Expense per Year Over 7 Years	Projected Interruptions Prevented per Year	Expense per Year per Interruption Prevented	Average Monthly Cost per Customer Served Over 7 Years	% Increase in Overall LVD Contractor Costs	Line Clearing Miles Not Completed per Year if No Incremental Funding
1	1st	All	$2,803,538	15,441	$182	$0.12	3%	192
2	1st and 2nd	Multiphase	$7,399,130	21,806	$339	$0.33	8%	506
3	1st and 2nd	All	$10,238,232	31,106	$329	$0.45	11%	700
4	All	Multiphase	$14,977,496	29,979	$500	$0.66	16%	1,025
5	Outside of 1st	All	$41,909,581	39,961	$1,049	$1.85	44%	2,867
6	All	All	$44,713,119	55,402	$807	$1.98	47%	3,059

3 TR 244.

Considering the data, Ms. Bolden preferred the first four options. She said, "Options one through four provide a lower contractor expense per year per projected reliability improvement (customer interruptions prevented) with a modest monthly impact to the average customer bill while remaining executable with the local workforce and not requiring out-of-state crews." 3 TR 244. "Alternatively," she said, "options five and six have a higher contractor expense per year per projected reliability improvement, would be more noticeably impactful to customer budgets, and would require out-of-state crews." 3 TR 244.

While recognizing the benefits of canopy removal, Ms. Bolden also cautioned that the Company's customers are not accustomed to this practice, so it could lead to "negative customer sentiment." 3 TR 244. To guide customer expectations, therefore, a "robust customer communication campaign would be required before and throughout the effort to remove canopy

in the chosen area(s)." 3 TR 244-245. Canopy removal would also "require additional use of specialty equipment in some areas (e.g., cranes)," which could exacerbate potential customer complaints and require additional safeguards. 3 TR 245.

The Company "does not recommend implementing any amount of more aggressive line clearing without incremental funding that supplements the base program." 3 TR 245.

c. Proposals to Further Reduce the Line Clearing Cycle

References in the Record: Denzler, 5 TR 3018-3022; Bolden, 3 TR 239-240, 248-252, Exhibit A-233 (PLB-12); Connolly, 2 TR 82

MNSC witness Denzler challenged the Company's proposed glidepath to a seven-year effective cycle as suboptimal. 5 TR 3018. Mr. Denzler compared Consumers Energy to DTE Electric, who he said has a five-year cycle, without comparing Consumers Energy's largely rural distribution system with DTE Electric's largely urban electric system. 5 TR 3018. Mr. Denzler also criticized the Company's Line Clearing Program Optimization Analysis that the Commission directed the Company to file in Case No. U-20697. The Optimization Analysis "account[ed] for customer costs of outages, the costs of service restoration, and the costs of line clearing." 3 TR 248. Mr. Denzler did not take issue with the data – only the Company's analysis and conclusions.[25]

A seven-year effective cycle is not suboptimal. Considering the record evidence in this case, including testimony about the Company's Optimization Analysis, the Company's proposed glidepath to a seven-year effective cycle remains the best option. As Ms. Bolden explained, "At current system status, the seven-year effective cycle . . . has [been] shown to be the most cost-beneficial approach to reducing tree-related outages on the LVD system when considering

[25] In this brief, the Company focuses largely on Mr. Denzler's critique of the Company's line clearing strategy, but the Company also does not agree with his recommendation that the Company update its Optimization Analysis by further analyzing the raw data to evaluate reliability benefits year over year and program costs. The analysis already evaluated pre- and post-clearing, year-over-year reliability metrics at the circuit-level and contractor expenses by work type for each headquarters. The additional information that Mr. Denzler requests would not add value. 3 TR 250.

Line Clearing Program costs and voltage-specific reliability." Speaking to the Optimization Analysis in particular, Ms. Bolden said that while it "differs from the previous analysis that resulted in the seven-year effective cycle by including measurements that had not been used previously, such as customer costs of outages, the results and ultimate recommendations are similar." 3 TR 248.

The Optimization Analysis showed that a four-year cycle was optimal for all customers – as the all-customer analysis was skewed by the benefit shorter line clearing cycles affords to non-residential customers – but a six- to seven-year cycle was optimal for residential customers who bear the bulk of line clearing and service restoration costs through rates. 2 TR 82; 3 TR 248; 5 TR 3019. Mr. Denzler applauded the Company for considering residential customers, particularly customers in environmental justice communities, and he proposed that the Company address the issue by "us[ing] the optimal cycle length, and then adjust[ing] the Cost-of-Service Study allocation to equitably distribute costs proportional to the benefits." 5 TR 3019. The solution, however, is not so simple. His proposal would be inconsistent with cost-causation principles that determine how costs are allocated.

As Company witness Laura M. Connolly explained, a Cost-of-Service Study ("COSS") "assigns costs to a class or group of customers based on how they drive or influence the utility's costs (e.g. cost causation)." 2 TR 82. For distribution costs, while shorter line clearing cycles may mean that C&I customers have "high avoided costs, largely attributable to lost business revenue [as longer line clearing cycles lead to longer outages], residential customers drive a larger share of investment in the low voltage distribution system." 2 TR 82. Further, "the COSS is concerned with ensuring that the parties that use and drive the investment in the asset and related costs pay

in proportion to that use." 2 TR 82. Allocating more line clearing costs to C&I customers would not be consistent with these cost-causation principles.

Despite offering no viable relief to customers from the costs of a four-year cycle, Mr. Denzler recommended that the Company "move aggressively towards" this cycle. 5 TR 3021. Such an aggressive move would harm customers and is not warranted. To be clear, the Company is not foreclosing the possibility of a shorter line clearing cycle in the long run – indeed, the Company is already on a glidepath to a shorter cycle – but it must balance the benefits of a shorter cycle against the costs. As Ms. Bolden aptly said, any potential cycle reduction must be "done at a deliberate pace that will not overburden residential customers." 3 TR 248. Aggressively moving to a four-year cycle would do just that – particularly for low-income residential customers.

Mr. Denzler hypothesized that one benefit of a shorter line clearing cycle is ease of access. When lines are not surrounded by dense vegetation, he said, it is easier and quicker for line crews and damage assessors to patrol the lines and see issues along the line. 5 TR 3022. The implication of his testimony is that the CAIDI is better for circuits with shorter cycle lengths because they are easily accessible. The outage and line clearing data says otherwise. The data does not show a relationship between CAIDI and ease of access. See Exhibit A-233 (PLB-12). Shorter cycles do improve CAIDI, albeit for a different reason. Namely, shorter cycles reduce CAIDI and costs per incident because there are fewer tree-caused outage incidents to drive work volume. 3 TR 252.

Mr. Denzler also recommended that the Company move to a true variable cycle based on actual vegetation risk conditions and implied that voltage classes are largely irrelevant. The Company does not agree that voltage classes are irrelevant – higher voltages are more sensitive to tree contact and susceptible to outages – but the Company shares his desire to better account for actual vegetation risk. 3 TR 239-240, 249, 317. In fact, the Company already "allows for variation

within each voltage class's intended cycle to account for differing conditions" and enhancing remote sensing and analytical tools "could help the Company further optimize line clearing cycles based on actual vegetation risk conditions." 3 TR 249. Moving beyond these tools, however, would require additional funding:

> While the Company does have its tree-related reliability predictive model (or "forestry model") and forestry workplan selection tool that uses the output of the forestry model, it does not have higher resolution remote sensing than publicly available National Agriculture Imagery Program (NAIP) satellite imagery and tree canopy cover data derived from it. The tree canopy cover data is integrated into the forestry model, which predicts tree-caused outages on a circuit-level. Many datasets help to improve forestry model accuracy, satellite imagery being one of them; however, satellite imagery at the resolution currently available to the Company cannot identify individual branches or easily identify individual trees that pose a risk to electric infrastructure. *As the Company does not have the remote sensing data mentioned in Mr. Denzler's testimony to identify all actual vegetation risk, this would require additional funding to supplement the forestry model.* [3 TR 249-250 (emphasis added).]

While the Company disagrees with Mr. Denzler on many fronts, the Company appreciates the overall thrust of his testimony, which is that the Company should consider a shorter line clearing cycle than a seven-year effective cycle in the future. It is. Looking forward, the Company is reconsidering the cycle length it is targeting and may propose changes in its next Reliability Roadmap or rate case. 3 TR 248. Still, the Company must first reach a seven-year effective cycle before it can move beyond this cycle. Currently, the Company is on a nine-year effective cycle. 3 TR 214, Figure 4. And the path to a six- or five-year cycle, if that is the Company's future, passes through a seven-year cycle. Whatever the future holds, the Company must continue to balance affordability and reliability, which is exactly what it has done in all of its analyses.

Setting the future aside for a moment, decisions in this case must be based upon the record in this case. MCL 24.285 ("A decision or order shall not be made except upon consideration of

the record as a whole or a portion of the record as may be cited by any party to the proceeding and as supported by and in accordance with the competent, material, and substantial evidence."). The record overwhelmingly supports the Company's proposal to continue its glidepath to a seven-year cycle, as the only party to suggest a shorter cycle suggested it for the next rate case. 5 TR 3021 ("[M]y primary recommendation is the Commission order the Company to move aggressively towards a four-year cycle and *include a plan for doing so in its next rate case*.") (emphasis added).

The Commission should address the next rate case's proposals in the next rate case; as for this one, the Company's proposal is the only one supported by the record

3. Service Restoration O&M Expense

References in the Record: Snider, 5 TR 2518-2520, 2524-2535, 2845-2846, 2547-2552; Exhibit A-107 (MPK-15); Conrad, 5 TR 1696, 1681; Kelly, 5 TR 884, 887, 935; Duell, 5 TR 3838; Evans, 5 TR 3960-3961; Lynd, 4 TR 524, 566-567, 569, 574, 580; Kurdziel, 5 TR 2029, 2035; Denzler 5 TR 3023-3024

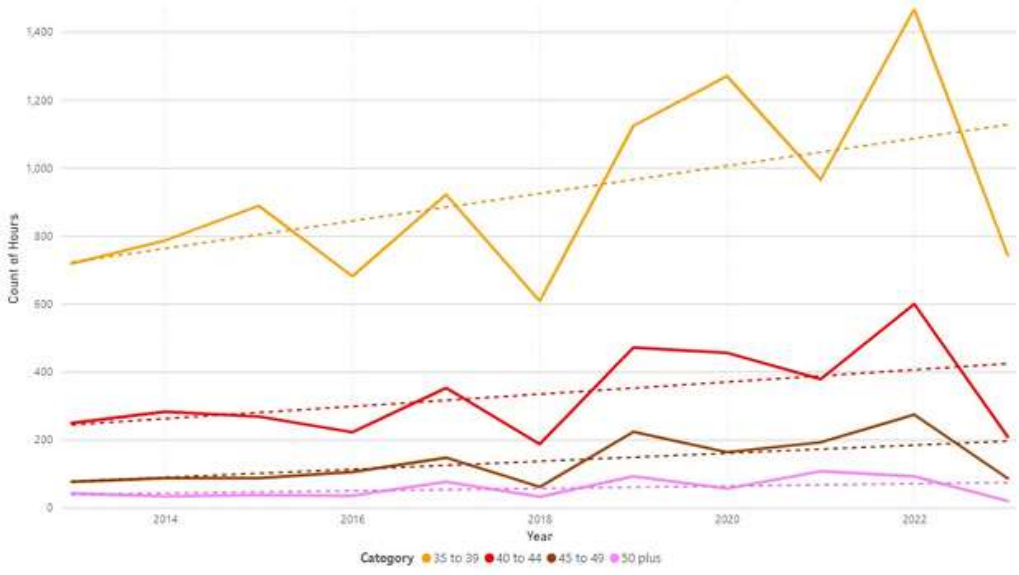
Company witness Snider projected that the Company's service restoration expense will be $133.5 million in the test year. 5 TR 2518; Exhibit A-107 (MPK-15). He based his projection on a five-year average of service restoration costs for 2019 through 2023, adjusted for inflation. *Id.* This spending represents the baseline needed to support the Company's efficient service-restoration practices and its continued efforts to reduce restoration times. The Company also proposes a Cost Sharing Mechanism for service restoration O&M expenses that would allow the Company to defer 50% of its service-restoration expenses when they exceed amounts included in rates while giving customers a 50% refund of the difference between actual annual spending and the amount included in rates when expenses are less than projected. This gives the Company an incentive to control costs and gives customers a refund when service-restoration expenses fall below amounts included in rates – an opportunity customers would not otherwise have. 5 TR 1696.

The Company's proposed storm restoration expense and Cost Sharing Mechanism will give "customers and the Company a level of financial clarity and appropriate risk-sharing in the wake of catastrophic storms, which are outside the control of the Company and of customers." 5 TR 2534. By approving the Company's proposed service restoration expense and the Cost Sharing Mechanism, the Commission will be ensuring that the Company has the resources it needs to quickly restore customers' power when their service is interrupted while letting customers share in the Company's success when it spends less than projected to restore power.

a. Service Restoration Expense

Service Restoration expenses have increased over the past five years as climate change drives severe weather and often violent, high-speed wind gusts. 5 TR 1681. Wind gusts can be even more damaging than sustained high winds, and both wind gusts and sustained winds have been getting increasingly worse in recent years. 5 TR 935. Although 2023 was an exception, the overall trend in each high-speed band is evident:

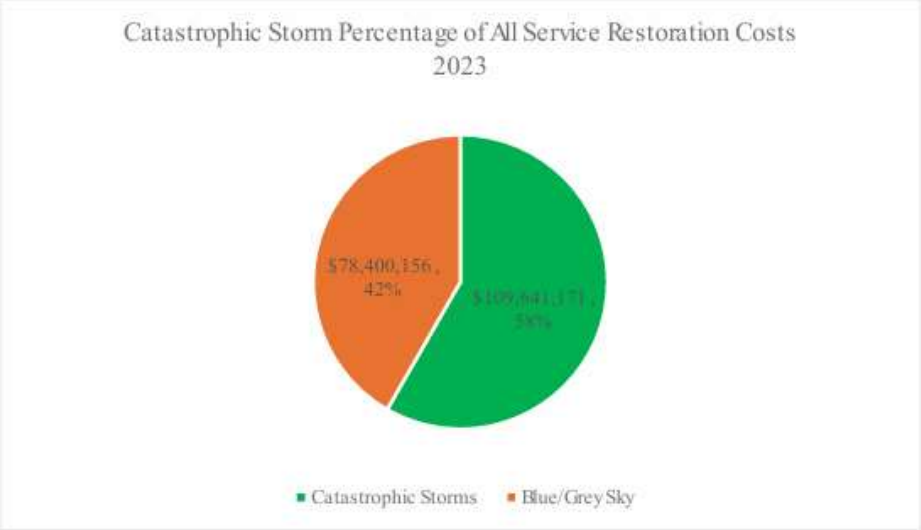
FIGURE 45
STATION HOURS EXCEEDING HIGH GUST THRESHOLDS, 2013-2023



5 TR 935.

This upward trend in wind gusts has led to more weather-caused customer outages. And while 2023 was less gusty than other recent years, it did feature a major ice storm in February 2023 that was the third largest outage event in the Company's service territory since 1998, as well as a severe weather system in August 2023 with several tornadoes that ranked fourteenth largest. 5 TR 935. Large catastrophic storms represent only a small fraction of total weather events, *but* they account for a much larger percentage of service restoration spending. 2023 is a prime example. The February ice storm and August storm accounted for 58% of total service restoration O&M spending:

Figure 4



5 TR 2522

Catastrophic storms are not only driving spending; they are becoming more prevalent. All climate scenarios modeled by the Company have resulted in more severe weather and extreme heat in future years. And recent experience bears this out. Of the top 15 worst storms (in terms of customer impact) in the last 25 years, four of them have occurred since 2020. 5 TR 2524.

In the face of increasingly severe weather, Consumers Energy has been preplanning and prestaging heavily to prepare for predicted weather events. The Company's Restoration

Management team continuously monitors weather to identify storm threats early. 5 TR 2524. According to Mr. Snider, when the Company identifies threats, its IBM outage prediction tool models potential impacts to the system, and the Restoration Management team uses the model to compare the prediction to comparable historical storm events. With this information in hand, he said, the Company develops a resource and execution plan to meet or exceed the Commission's service quality standards. 5 TR 2524. This "rigor in preplanning is the foundation of an efficient restoration by ensuring our plans are scaled appropriately for the impacts, because oversizing or under sizing the resource plan would result in additional costs for our customers." 5 TR 2524.

By prestaging, the Company mobilizes its contract and in-house crews before severe weather strikes to have them ready on location to respond quickly to outages. 5 TR 2551. The Company is increasingly relying on its own workforce and less on contract crews. Company crews complete more than twice as many orders per shift than contract crews and have a 33% cost advantage. 5 TR 2525. So, as the Company's preplanning has matured, it has been able to rely less on mutual assistance and broker 25% fewer contract crews, with plans to further reduce contract crews by 25% over the next two years. To achieve this, the Company executed a storm on-call agreement with its internal union workforce to be more proactive securing and prestaging internal crews to rapidly and cost-effectively restore customers' power. 5 TR 2524-2525.

In 2023, Consumers Energy also took other steps to reduce costs. Through competitive bidding, the Company secured 46 vendors with more than 1,300 crews under contract to respond to storms. All 46 vendors are ranked by cost from lowest to highest, and the Company developed a standard to engage the lowest cost resources first. 5 TR 2525. As this process is further refined, the next step is to study vendor productivity and overlay performance with cost to inform the selection process and call contractors in a sequence that provides the overall best value for

customers. Relying on these vendors will also mean less mutual assistance from investor-owned utilities that comes at a premium. 5 TR 2525.

Beyond this, the Company is constantly evaluating its processes and procedures. It has observed that there is an inverse correlation between crew size and productivity when more than seven contract crews are assigned to a supervisor. To avoid overwhelming supervisors, therefore, the Company has improved its standards to increase productivity. 5 TR 2526. At the same time, the Company continues to innovate. It is developing better tools to assess damage and monitor work orders for broken poles, downed wires, and other storm damage, like the Company's new work planning application. It provides near real-time information about circuit damage and the materials and equipment needed for each job to restore power faster. 5 TR 2526.

The Company is doing good work to improve its service restoration times in the face of increasingly severe weather, and it asks the Commission to approve $133.5 million to support its efforts in the test year. Staff supports the Company's proposed O&M expense. 5 TR 3838. Attorney General witness Coppola recommended a $124.9 million expense level. 5 TR 2845. He argued that the Company should not have excluded insurance proceeds or voluntary refund mechanism credits from its historical service restoration expenses because the Commission did not exclude them in the Company's last rate case. 5 TR 2846. He mistakenly claimed that Company witness Snider did not raise any new arguments that should lead the Commission to reach a different conclusion when, in fact, Mr. Snider did introduce new evidence on this topic.

Mr. Snider explained that there were two reasons why he removed insurance proceeds and credits from his five-year average service restoration expense:

1. The Company's service restoration insurance ended in 2019, with all claims finalized in 2020, and the Company does not intend to purchase storm restoration insurance; and

2. The Voluntary Refund Mechanism ("VRM") amounts were the result of a one-time, voluntary refund designated for storm restoration activities as a result of the Commission's approval of this VRM refund in Case No. U-20932. Subsequently, the Commission denied Consumers Energy's proposal to use VRM refund amounts for storm restoration activities in Case No. U-21332. The Company does not anticipate future VRM funds to be used for storm restoration. [5 TR 2519-2520.]

Mr. Snider further explained why the Company terminated its storm restoration insurance coverage and why it does not expect further voluntary refund adjustments in the projected test year. The policy was not renewed because premiums increased by 137% and, based on historical experience, the Company does not expect to receive proceeds justifying the higher cost. 5 TR 2520. Nor does the Company expect storm insurance to be economical in the future, which is why the Company does not intend to renew the policy. The policy's benefits simply are not worth the cost. 5 TR 2520.

As for the voluntary refund mechanism credits, Mr. Snider testified that there will be no credits for storm restoration expenses in the projected test year because Consumers Energy does not intend to request a voluntary refund for storm restoration expenses and, in Case No. U-21332, the Commission rejected the Company's request to use voluntary refunds to offset storm restoration expenses. 5 TR 2543.

Mr. Coppola also claimed that the Company's service restoration forecast did not capture $0.78 million in forestry savings. The Company is gradually clearing more circuit miles every year, which reduces customer outages and service restoration costs. As a result, the Company removed $0.51 million in expected savings from projected test year amounts. Mr. Coppola said the Company underestimated its savings, but it did not. There are two basic reasons why:

1. The calculations that underlie this proposed disallowance are incorrect as they are based on the cumulative incident savings, and not on the annual savings from one year to the next. Mr. Coppola first calculated the average rate of decline in tree-related outages from 2019 through 2023 and then extended this rate of decline into 2024, 2025, and 2026 to project the cumulative savings in 2026. But to

accurately project test year costs, the goal should be to isolate projected test year savings and not calculate cumulative savings.

2. Mr. Coppola also did not consider that, as more circuits are cleared on the LVD system on shorter cycles, there will be fewer tree-caused outage incidents, which leaves fewer opportunities for savings when the on-cycle circuits are cleared again. The Company's calculation accounts for this fact, see Exhibit AG-1.36, but Mr. Coppola's calculation does not.

The Company's service restoration efforts advance electric reliability by helping to mitigate customer outages, and the Company should be allowed to recover its full projected service restoration expense, subject to the Cost Sharing Mechanism discussed below.

b. <u>Service Restoration Cost Sharing Mechanism</u>

If the Commission approves the full amount that the Company is requesting for its service restoration expense, and especially if it approves a lower amount, it will still not be enough to cover the Company's service restoration costs in some years. Volatile weather drives the Company's service restoration expenses. While $133.5 million would more than cover the Company's service-restoration expenses in a good-weather year with fewer MEDs than a usual year, $133.5 million would not cover the Company's service-restoration expenses in a bad-weather year with more MEDs than usual.[26] Last year was a prime example of the lopsided potential inherent in the current system beholden to volatile weather patterns.

In 2023, the Company spent about $188 million restoring customers' power, representing 18% of the Company's total O&M budget that year. 5 TR 2519, 2548. When compared to the amount the Company projected it would spend in 2023 (approximately $105 million), see MPSC Case No. U-21389, March 1, 2024 Order, page 171, the disparity is obvious. The Company spent approximately $83 million more than projected. And 2024 is not far off. Through the end of

[26] "A MED is an Institute of Electrical and Electronics Engineers ("IEEE") 1366 standard that involves a large number of incidents in a short period of time due to extreme weather events." 5 TR 1689.

September 2024, the Company had spent $143 million restoring power, which already "exceeds the amount included in rates for service restoration in Case No. U-21389 ($104.23 million) for the entire projected test year in that case" by approximately $40 million. 5 TR 2545-2546.

For bad-weather years like 2023 and 2024, as well as good-weather years when the Company's service restoration expenses fall below expectations, the Company's Cost Sharing Mechanism makes sense. In the bad years, the Company could defer and ultimately recover 50% of its excess service-restoration expense (i.e. expenses above approved amounts included in rates). In the good years, customers would receive a refund for 50% of expenses below approved amounts included in rates. 5 TR 2531-2532.

The simplicity and symmetry of the mechanism ensure that customers benefit in any scenario. When the weather is unpredictably bad, customers can be assured that the Company will have access to the resources needed to quickly restore customers' power. Conversely, if weather is unpredictably good, resulting in a lower restoration expense than the amount included in base rates, customers will receive a refund under the mechanism. 5 TR 2546.

The mechanism is also an incentive for the Company to control costs. It limits the Company's potential recovery for amounts spent above base rates to 50%, which is an incentive to control storm restoration costs so that it does not lose out on 50% recovery above base rates. It is also an incentive to continue improving efficiencies and spend less than the base amount, as it retains 50% of its restoration savings when it spends less than the base amount. 5 TR 2533.

Finally, the mechanism advances the Company's efforts to meet the Commission's Service Quality and Reliability Standards and to continually improve its performance. As Mr. Snider explained, the mechanism does so by giving customers and the Company financial clarity and

sharing the risk inherent in catastrophic storms. It not only mitigates risks, it also equally distributes benefits better than the status quo, which creates winners and losers when either:

(1) The Company shoulders the increased costs of catastrophic storms when the costs exceed the service restoration expense included in base rates; or

(2) Customers do not benefit from reduced costs when catastrophic storms do not occur and costs are below the service restoration expense included in base rates. [5 TR 2534.]

In Case No. U-21389, the Commission made it clear that if the Company was to propose another service restoration mechanism, it would need to make some changes. The Company heeded the Commission's words, see 5 TR 2534-2535, and the Cost Sharing Mechanism it has proposed is, far and away, the best mechanism it has ever proposed. The mechanism benefits customers in any scenario, and the Commission should approve it.

i. Response to Staff

Despite its well-balanced structure, Staff opposed the Company's proposed Cost Sharing Mechanism. Staff witness Duell opposed the mechanism for four reasons: (1) Staff already supports the full service restoration expense included in the test year; (2) the Commission has rejected similar proposals in the past; (3) Staff does not believe customers will benefit given trending weather patterns in the state; and (4) the status quo provides a stronger incentive to control costs than the Company's proposal. 5 TR 3960-3961. Generally speaking, Staff appears to view the Company's proposed Cost Sharing Mechanism as just the next iteration in service restoration mechanisms when, in reality, it is the culmination of years of experience and the apex of mechanisms proposed to date. It is perfectly balanced and designed to provide the Company with the right incentives to control costs and improve restoration times affordably for customers.

Concerning Staff's first reason, the Company's proposed service restoration expense is a solid baseline for service restoration cost recovery, but it is not necessarily the "full" service

restoration expense, as Ms. Duell implied, and does not account for volatile weather. When severe weather strikes, actual service restoration costs can diverge, sometimes drastically, from the amount the Company included in its projected test year. Since 2019, the Company has spent $341 million more to restore power than was approved in rates for those years using the five-year average to set the expense level. 5 TR 2545. And as pointed out above, through the end of September 2024, the Company has incurred approximately $40 million more than what was included in rates. The Cost Sharing Mechanism would allow the Company to manage this volatility while maintaining an incentive to control costs and improve performance.

Concerning Staff's second reason for opposing the mechanism, previous Commission rulings rejecting other mechanisms are not a good reason to reject a different proposal in this case, particularly when the Company went out of its way to address the Commission's concerns from past cases. See 5 TR 2534-2535. Historically, parties who objected to the service restoration mechanisms proposed in earlier cases questioned whether they had appropriate incentives to control costs and improve performance. There are no grounds for similar concerns about the Company's proposed Cost Sharing Mechanism in this case, as it provides the right incentives. Also, the Company has recently made progress cutting costs and accelerating restoration times that will continue with the proposed mechanism in place:

> In spite of a 9% increase in interruptions through the first three quarters of 2024, driven by three catastrophic events on May 7, 2024, June 25, 2024, and August 27, 2024, the Company has nevertheless spent 13% less on O&M restoration through September 2024 than it did over the same period in 2023. In terms of restoration performance, the Company is on track to meet all Service Quality and Reliability Standards for Normal Conditions, Gray Sky Conditions, Catastrophic Conditions, and All Conditions in 2024. [5 TR 2547.]

Further, Mr. Snider pointed out that the Liberty Consulting Group ("Liberty") recently audited the Company's distribution system and its processes and procedures, including service restoration procedures, and concluded that "***Consumer's restoration performance***, measured by the average duration of classified storm types, ***show marked improvement in recent years*** across all storm classifications except for Catastrophic" storms. 5 TR 2547. Approving the Company's proposed Cost Sharing Mechanism would not reverse these gains even if there were no incentives to control costs and improve performance – and more so since the mechanism does have built-in incentives to promote both. The Company also has proven leadership to carry it out. Mr. Snider again cited a Liberty finding supporting this conclusion where it observed that the Company's "organizational focus on visual management, problem solving and continuous improvement was repeatedly demonstrated . . . at all levels of leadership." 5 TR 2547.

Staff's third argument – that customers will not benefit from the mechanism given trending weather patterns – contains two false premises: (1) it assumes that customers do not benefit if the mechanism operates in bad-weather years when the Company spends more than projected; and (2) it assumes that there will not be years when the Company spends less than projected. "Customers want and deserve prompt storm restoration service," and Staff's first assumption is wrong because the proposed mechanism provides customers with "a degree of certainty that when a catastrophic storm impacts Michigan, the Company will have the resources to continue to deliver for customers." 5 TR 2548. Mr. Snider pointed to recent severe weather in Ohio and Florida to illustrate the vital need for cost recovery to be able to effectively perform storm restoration work. 5 TR 2548.

Staff is also wrong to assume that there will not be years when the Company spends less than projected. This would be true only if the trend is inviolable and there is no variation within

trending weather patterns. The weather, while getting worse overall, is still volatile. No one should assume that the weather will always be worse than the five-year average. And, when the weather is unpredictably good, as it inevitably will be, and the Company spends less to restore power than the amount included in base rates, customers will benefit from a refund under the mechanism. In this way, the proposed mechanism appropriately balances the risk of variations in storm restoration expense between the Company and customers. 5 TR 2549.

Staff's final argument – that the Company currently has a stronger incentive to control costs than it would if the Company's proposed Cost Sharing Mechanism is adopted – overemphasizes cost controls at the possible expense of restoration times. Cost controls, though important, should not be the sole objective if faster restoration times are also desired. Forcing the Company to "shoulder the full burden of the cost risk provides an incentive to prioritize cost control over restoration performance." 5 TR 2549.

A well-structured incentive construct should match desired outcomes and balance penalties and cost recovery. The current construct does neither; rather, as Mr. Snider testified, it is penalty heavy. 5 TR 2549. "The Company's proposed Cost Sharing Mechanism," by contrast, "would provide the Company an incentive to improve restoration times that does not just penalize the Company but also provides for partial cost recovery when bad weather drives up service restoration costs." 5 TR 2549.

The Company urges the Commission to adopt the Company's proposed Cost Sharing Mechanism over Staff's recommendation to the contrary. The need is plain to see and comes into sharper focus with each passing year as the Company experiences multi-million dollar swings in its service restoration expense from one year to the next. There is a better way to manage these swings and distribute their benefits and burdens. And the Cost Sharing Mechanism is that way.

ii. Response to the Attorney General

Attorney General witness Coppola opposes the mechanism for some of the same reasons as Staff and some different ones. Mr. Snider summarized these reasons as follows: "(1) the proposal has not changed much; (2) similar proposals have been rejected; (3) the proposed service restoration recovery amount is the highest it's ever been; (4) increases have been driven by additional people in the Incident Command System ("ICS") and preplanning that are unjustified; and (5) diminishing incentive for the Company to improve on restoration." 5 TR 2549-2550. Mr. Coppola's critiques are superficial and lack nuance.

Contrary to Mr. Coppola's claim, the proposed Cost Sharing Mechanism is different and improved from prior proposals and reflects Commission feedback. In Case No. U-21389, the Company proposed a Symmetrical Performance Incentive Mechanism, which included full recovery or refund outside of a 10% margin of error above or below the amount set in rates. With this 10% deadband, customers would not have received a refund unless expenses were more than 10% below approved amounts, and the Company would have fully recovered expenses above 10% of approved amounts. 5 TR 2550.

The Cost Sharing Mechanism proposed in this case has no deadband where the Company could be the only beneficiary. Plus, the Company could not recover more than 50% of any overage through the deferred recovery process. This differentiates the proposal from previous proposals in a simple but meaningful way: the risk and reward is shared equally between the Company and customers. 5 TR 2550. Similarly, Mr. Coppola also argued that the Commission has rejected similar proposals, but as the Company pointed out in response to Staff, the Company crafted a new Cost Sharing Mechanism in this case with different features to address past Commission rulings.

Next, Mr. Coppola argued that the proposed service restoration expense is the highest it has ever been and claimed that "[t]he law of averages dictates that costs in future years will likely be less than the highest amount included in the average." 5 TR 2874. Indeed, the Company continues to anticipate that it will be subject to increasingly volatile and unpredictable weather events – events that are worse than expected in some years and better than expected in others. To the extent costs are less than the five-year average included in base rates, which is a likely eventuality, the mechanism will result in a customer refund. 5 TR 2551.

Mr. Coppola's next argument is puzzling. He claims that unnecessary ICS team members and unnecessary prestaging are driving up costs and inefficiencies. In reality, the ICS is designed to be a scalable system engaging resources *as needed* to manage incidents. 5 TR 2551. As for prestaging, it is a best practice that only accounts for about 3-4% of the total restoration spending. Liberty recognized its value in its recent audit: "Importantly, the Company pre-stages crews when conditions warrant, which represents an effective and best practice means of shortening restoration duration." 5 TR 2551 (quoting Liberty's Report, Part II, page 101).

Finally, Mr. Coppola is wrong to suggest that the Cost Sharing Mechanism would diminish incentives to control costs and improve performance. As Mr. Snider explained, "There is absolutely no upside for the Company to spend more than is recoverable; overspending is always an undesirable financial outcome." 5 TR 2552. A well-structured incentive construct should match desired outcomes and balance penalties and cost recovery, and the Company's proposed mechanism does both.

The Company urges the Commission to adopt the Company's proposed Cost Sharing Mechanism over the Attorney General's recommendation to the contrary.

iii. Response to the MNSC

MNSC witness Denzler claims that the Company's proposed Cost Sharing Mechanism is not good for customers and creates imbalanced risk, even implying that the Company will somehow benefit from the risk that severe weather and natural disasters pose if the Company's proposed mechanism is approved. 5 TR 3023-3024. He could not be more wrong. While the Company would recover 50% of any service restoration cost overruns under its proposed mechanism, this is hardly an incentive to overspend when the Company would lose 50% of all the cost overruns. Ultimately, both the Company and customers shoulder risk related to natural disasters that affect Michigan's communities but are outside the Company's control. The proposed Cost Sharing Mechanism is an appropriately balanced way to share this risk. 5 TR 2552.

Mr. Denzler alluded to "supposed" improvements in the Company's restoration performance and says he has "yet to see sufficient evidence of sustained improvement." 5 TR 3024. Mr. Snider, however, specifically explained how the Company has improved its restoration times in a cost-effective manner. 5 TR 2524-2531. And Mr. Denzler did not address Mr. Snider's testimony about the work being done to improve performance cost effectively, so there is little to say in response. Besides Mr. Snider's testimony, Company witnesses Kelly, Lynd, and Kurdziel each described the sustained improvement that the Company has seen in SAIDI and SAIFI metrics through investments in the distribution system. 4 TR 524, 566-567, 569, 574, 580; 5 TR 884, 887, 2029, 2035.

Mr. Denzler also alleges that the Company's proposed mechanism would misalign incentives for the Company to expand the scope of service restoration work. 5 TR 3024. This is a vague allegation about which, again, little can be said. There is one variable that determines the scope of service restoration work – the damage caused by the outage event. The Company does

not benefit from somehow expanding service restoration costs beyond what is needed to restore customers' power. The Company's objective is to reduce the scope and impact of storms as efficiently as possible. The proposed mechanism provides the right incentives to do this. 5 TR 2554.

Finally, Mr. Denzler seeks to link the Cost Sharing Mechanism proposed in this case with service restoration mechanisms proposed in earlier cases to argue that the Commission's statements in earlier cases preclude the mechanism proposed in this case, and he seeks to tie the financial recovery to a new proposed set of service restoration performance metrics. The Cost Sharing Mechanism stands on its own merits. In combination with reliability investments, it provides customers another way to benefit from reliability improvements that will lead to fewer outages and reduced restoration costs. 5 TR 2555. As for new metrics, the Commission already has stringent service quality standards, and there is no need for additional metrics. 5 TR 2556.

The Company urges the Commission to adopt the Company's proposed Cost Sharing Mechanism over MNSC's recommendation to the contrary.

4. Generation O&M Expense

References in the Record: Blumenstock, 5 TR 1491-1493, 1498-1532, Exhibit A-43 (RTB-4); Coppola, 5 TR 2858

a. The Commission Should Approve the Company's Projected Generation O&M Expense Levels

Company witness Blumenstock supported Consumers Energy's Fossil and Hydro Generation O&M expenses. He described how the expense items that compose the overall portfolio of Fossil and Hydro Generation-related O&M expense were developed for the test year. 5 TR 1491-1493. Exhibit A-43 (RTB-4) summarizes the Company's projected Fossil and Hydro

Generation O&M expenses. For the test year, Mr. Blumenstock projected a total Fossil and Hydro Generation O&M expense amount of $111.851 million.[27] 5 TR 1493; Exhibit A-43 (RTB-4).

Exhibit A-43 (RTB-4) separates the Company's Base O&M and Adjusted O&M expenses, with the Adjusted O&M expense comprising Environmental Operations, Major Maintenance, and Retention and Separation Plan expenses. Mr. Blumenstock explained that Base O&M includes labor and non-labor components. 5 TR 1492. 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. 5 TR 1492.

With respect to Environmental Operations, the Company projects that it will spend $2.584 million during the test year. Exhibit A-43 (RTB-4), page 1, line 3, column (d). Mr. Blumenstock explained that Environmental Operations expenses are a combination of O&M costs related to the environmental equipment at the Karn and Campbell sites. 5 TR 1498. The operations component is primarily calculated using labor costs for operations and environmental waste disposal; the maintenance component is based on a combination of historical and estimated planned maintenance costs on the specific components of environmental equipment. 5 TR 1498-1499.

With respect to Major Maintenance costs, the Company projects that it will spend $31.203 million during the test year. 5 TR 1500; Exhibit A-43 (RTB-4), page 1, line 4, column (d). In support of its Major Maintenance expenses, Mr. Blumenstock provided detailed discussion throughout his testimony regarding the specific plants that the Company expects to require Major

[27] If the Commission agrees to move the Company's solar projects from this case to the Company's Renewable Energy Plan Amendment as proposed by Staff and as discussed in Section III.A.3.d of this Initial Brief, this amount should be reduced by $3.252 million to reflect the O&M associated with those projects. See Staff Exhibit S-9.

Maintenance projects during the test year. 5 TR 1503-1512. Due to the number of factors involved, it is possible that the Company's forecasted Major Maintenance plan could change. 5 TR 1501. Equipment condition can change such that the timing of maintenance activities may need to be accelerated or delayed. 5 TR 1501. Factors such as weather, equipment and labor availability, energy market conditions, and electrical system stability can affect the actual timing of an outage and maintenance spending. 5 TR 1501. The requested O&M expenses are necessary and reasonable to continue Consumers Energy's successful operation of the generation fleet.

Mr. Blumenstock also described the Karn and Campbell Retention and Separation Plan expenses. See 5 TR 1512-1521. He explained that the plan is a people strategy that the Company has implemented to ensure that it can retain the necessary qualified employees to operate Karn Units 1 and 2 and the Campbell plant through their retirement dates, as well as during the cold and dark period following retirement. 5 TR 1513, 1517-1518. The Company's 2018 IRP and 2021 IRP included detailed support of the Company's need to implement a retention and separation plan to ensure that it could operate Karn Units 1 and 2 and the Campbell Plant safely and reliably through the plant retirement dates. 5 TR 1514, 1517.

The Company has a strong interest in keeping qualified employees working at Karn Units 1 and 2 and the Campbell Plant through plant retirement to ensure safe and reliable operations. 5 TR 1514, 1518. The retention component will allow the Company to retain employees who may seek employment at other Company locations or outside of the Company. 5 TR 1514, 1518. The Company's ability to hire new employees at Karn Units 1 and 2 and the Campbell Plant will become increasingly difficult given the short remaining lifespan of the plants and, to the extent that the Company has the ability to hire new employees, the training time necessary for any new hires will provide a significant challenge to operating the units both safely and reliably. 5 TR

1514, 1518. The retention component utilizes the best practices that the Company employed in retiring the Classic 7 (the electric generating units that were located at the Cobb and Whiting plants). 5 TR 1514.

The Karn and Campbell retention and separation plan includes three benefit types: retention benefits, severance benefits, and relocation and moving costs. 5 TR 1515, 1519. The retention benefits associated with the Karn and Campbell retention and separation plan include three payment components: a signing incentive, annual incentives, and a final retention incentive. 5 TR 1515, 1519.

Mr. Blumenstock provided the Company's projected costs for the Company's retention and separation plan in his Exhibit A-43 (RTB-4), page 1, line 5. As reflected on Exhibit A-43 (RTB-4), page 1, line 5, the Company incurred actual expense of $17.348 million in 2023 and is projecting expense of $11.158 million in the 14-month projected bridge period and $4.621 million in the test year. The actual 2023 retention and severance expense is based upon expense of $1.501 million for the Karn site and $15.847 million for Campbell. 5 TR 1512-1513. The entire projected bridge year expense of $11.158 million is based upon expense for Campbell. 5 TR 1513. The projected test year expense of $4.621 million is based upon expense for Campbell. 5 TR 1513.

Mr. Blumenstock explained that the Company is not requesting O&M recovery of the $4.621 million projected amount for the test year. 5 TR 1513. The Company received approval in Electric Rate Case No. U-20697, to defer the recovery of the Karn Retention and Separation O&M amounts for 2021 through 2023. 5 TR 1513. The Company received approval to defer the recovery of the Campbell retention and separation amounts as part of its approved settlement agreement in the 2021 IRP. 5 TR 1513. As such, the projected amounts for 2023 through the

projected test year are not included in the Total O&M amounts on Exhibit A-43 (RTB-4), page 1, line 6, columns (b), (c), and (d).

The Commission should approve the $111.851 million of generation O&M expense for the test year supported by Mr. Blumenstock in Exhibit A-43 (RTB-4), page 1, line 6, column (d).

b. The Commission Should Reject the Attorney General's Proposed Generation O&M Disallowances

Attorney General witness Coppola recommended two disallowances to reduce the Company's forecasted generation O&M expense in this case. He proposed a $1.308 million disallowance related to the forecasted O&M expense for the Croton hydroelectric plant and a $3.75 million disallowance for the Company's forecasted Base O&M at the Karn plant. There is no merit to either proposed disallowance. The Company discusses each of Mr. Coppola's proposed disallowances in more detail below.

i. There Are Several Errors in the Attorney General's Rationale for the Proposed Croton O&M Disallowance

Mr. Coppola recommends that the Commission disallow $1.308 million of the Company's projected generation O&M expense related to the O&M for the Croton hydroelectric plant. 5 TR 2857. Mr. Coppola claims that the Company's projected test year total O&M amount, which he claims to be $3.055 million for Croton, significantly exceeds the Company's three-year average O&M expense for the plant and that there is no explanation for the increase. 5 TR 2857.

There are several problems with Mr. Coppola's analysis. First, Mr. Coppola states an incorrect amount of O&M in the Company's case for the Croton plant. He claims the Company requested $3.055 million of test year O&M for Croton, when in fact the Company's request was actually only for $3.001 million of O&M. Mr. Coppola inadvertently attributed $53,333 for a project at the Company's Cook hydroelectric plant to Croton. 5 TR 1529.

Second, contrary to Mr. Coppola's claim, the Company identified three specific projects that support the entire amount of the $3.001 million O&M amount the Company forecasted in this case: (i) Croton Headquarters License/Fees (Regulatory) ($165,460); (ii) Croton Headquarters Maintenance ($1.253 million); and (iii) Croton Headquarters OPS ($1.583 million). 5 TR 1528. Mr. Blumenstock testified that these projects cannot be avoided if the Company wants to continue to operate the Muskegon River Hydro Units in a safe and reliable manner. 5 TR 1528. Mr. Blumenstock also explained that there has been an increase in the scope of work required at the Company's River Hydro plants due to an increase in the scope of the Company's FERC Part 12 inspections, which now require comprehensive assessments in addition to the periodic inspections. 5 TR 1528. This required the Company to add headcount and additional contracted engineering services. 5 TR 1528. Additional work and additional employees and contractors obviously necessitate additional costs above historic year amounts. Furthermore, with respect to Mr. Coppola's claim that the Company failed to provide any support for its O&M forecast, Company witness Blumenstock notes that Mr. Coppola did not submit any follow-up questions to his original data request providing the details of the River Hydro O&M spending in this case. 5 TR 1529.

Third, Mr. Coppola failed to understand that the forecasted Croton O&M expense amount he proposed to cut is not solely attributable to Croton. Therefore, it was not correct to compare the test year amount to the historical amount for Croton alone. Mr. Blumenstock testified that the O&M expense projected for the Croton Hydro Unit "is based upon the Croton Headquarters which provides maintenance and operations for all three Muskegon River Hydro Units--Croton, Hardy, and Rogers." 5 TR 1529. He explained that, when the Company incurs the actual O&M expense for these projects, it "can be recorded to the individual facilities as compared to the projection";

however, Mr. Coppola did not include any of the historical expense for the Hardy and Rogers Hydro Units in his analysis. 5 TR 1529. If Mr. Coppola had applied his same methodology for calculating his proposed disallowance, but used the historical average of the O&M expense for Croton, Hardy, and Rogers, the result would have shown that the inflation adjusted average O&M for the last three years was $2.910 million, which is only a difference of $91,000 compared to the Company's forecast of $3.001 million, and that is without accounting for the increased scope of work. See 5 TR 1529.

There is no validity to Mr. Coppola's rationale for proposing the disallowance for the Croton plant O&M. The Commission should reject his proposed disallowance and approve the O&M amounts forecasted by the Company.

ii. The Attorney General's Proposed Disallowance for the Karn Base O&M is Based on Unsound Assumptions and Incorrect Calculations

Attorney General witness Coppola recommended that the Commission disallow $3.745 million of the Company's Base O&M for the Karn Plant. 5 TR 2858. However, his method for calculating this reduction is flawed. Mr. Coppola observed that Karn Units 1 and 2 were retired at the end of May 2023 and claims that the O&M for Karn reduced by $10.207 million in 2023 compared to the two-year average from the previous two years. 5 TR 2858. However, Mr. Coppola's two-year average from the previous two years ($26.761 million) was incorrect. Company witness Blumenstock testified that the actual two-year average was $27.761 million. 5 TR 1531. As a result, Mr. Coppola's calculation of the reduction experienced in 2023 after the retirement of Karn Units 1 and 2 is incorrect – it actually understates the $11.207 million reduction that the Company experienced. 5 TR 1531.

Thereafter, Mr. Coppola assumes – without any basis – that the incorrect $10.207 reduction for the last seven months of 2023 can simply be "annualized" to arrive at an expected reduction

amount for Karn Units 1 and 2 that Mr. Coppola can subtract from the average O&M from the prior two years. 5 TR 2858. That is not a correct assumption. Mr. Blumenstock explained that Karn Units 1 through 4 shared employees for both operations and maintenance activities and the cost of security and facilities. 5 TR 1532. Those costs still exist even though Karn Units 1 and 2 have been retired and they must now be fully allocated to Karn Units 3 and 4. 5 TR 1532. Mr. Blumenstock testified that there are $2.355 million of annual O&M expenses for the Karn site that would have been previously attributed to Karn Units 1 and 2 that were not eliminated when those units retired and that must now be spent on Karn Units 3 and 4. 5 TR 1532.

Even if Mr. Coppola's assumption about "annualizing" the observed savings for Karn Units 1 and 2 were correct (which they are not), Mr. Coppola did not perform the calculation correctly. Although he recognized that the Company retired Karn Units 1 and 2 with seven months remaining in 2023, he nevertheless multiplied his incorrect estimate of seven months of savings by two, which would produce an estimate for 14 months of savings – not 12 months as Mr. Coppola claimed. 5 TR 2858; see also 5 TR 1531. Mr. Blumenstock recalculated the correct annualized reduction using the correct $11.207 million of savings in the last month of 2023 and by correctly prorating the seven months of savings over 12 months. 5 TR 1531-1532. The correct savings compared to the previous two-year average of O&M expense would be $1.437 million after accounting for inflation – not the $3.745 million that Mr. Coppola calculated. 5 TR 1532.

Once that savings is offset by the amount of Karn Unit 1 and 2 shared O&M expense that must now be carried by Karn Units 3 and 4 ($2.355 million), it is clear that the Company's Base O&M estimate for Karn in the test year is actually conservative. The Commission should reject the Attorney General's flawed analysis, which was based on unsound assumptions and a mathematically incorrect "annualization" calculation. Mr. Blumenstock noted that the inability to

operate Karn Units 3 and 4 would impact the capacity value that those units provide for customers, which is approximately $55 million per year based on 75% of CONE. 5 TR 1533. Mr. Coppola's proposed disallowance will harm customers. The Commission should approve the Base O&M forecasted by the Company for the Karn plant.

5. Operations Support O&M Expenses

References in the Record: Guinn, 5 TR 1837; Exhibit A-81 (QAG-2)

The Company's Operations Support O&M expenses relate to Facilities, Real Estate, and Supply Chain. 5 TR 1837. The Company is projecting to spend $9.525 million in Electric Operations Support for the test year. This spending is allocated between Facilities, Real Estate, and Supply Chain. 5 TR 1837. The facilities work includes items such as maintenance and repair of HVAC systems, miscellaneous building repairs, yard maintenance and snow removal, and daily cleaning or other major scheduled cleaning projects such as windows and carpeting. *Id*. The real estate services include: (i) management of all land-related uses of easements and rights of way, including encroachments, third-party requests for use of Company property, land-owner requests for modification of easement rights or approval of permission to construct within an easement as well as management of all corporate facility leases; (ii) responses to all requests to sell property or grant easements, leases, or licenses to third parties; and (iii) records management function that is responsible for maintenance of a land inventory and Geographic Information System mapping for property ownership and rights of -way. *Id*. Additionally, supply chain assists with vendor and contract management, purchasing of materials and services, and document reproduction. *Id*. Exhibit A-81 (QAG-2) details the O&M costs related to Operations Support.

6. Customer Experience O&M Expense

References in the Record: McLean, 5 TR 2140- 2198; Exhibit A-130 (SQM-2); Klocke, 5 TR 3729-3730; Exhibits S-13.7, S-13.8, and S-13.9; Coppola, 5 TR 2859-2860

Company witness McLean presented the O&M expenses related to the Company's CX&O organization. CX&O consists of two major organizations supporting the core strategy of connection and communication for interacting with the Company: (i) Customer Interactions, which ensures all customers are equipped to seamlessly connect with the Company in their preferred channel (phone, Interactive Voice Response (IVR), website, mobile app, or digital correspondence – such as text messages); and (ii) Billing and Payment, which provides customers with timely and accurate bills, consistent payment processes, and personalized payment plans or settings (e.g. inability to pay arrangements, pay by phone/website, payment alerts, choose your own bill due date) for individual customers. 5 TR 2143. Through the efforts in these organizations, Consumers Energy strives to optimize the positive experience electric customers have when interacting with the Company. 5 TR 2143. The Company projected a test year total CX&O expense of around $35.710 million, which includes $25.358 million of O&M expenses for Customer Interactions and $10.352 million in expenses for Billing and Payment. Exhibit A-130 (SQM-2). The Commission should approve the Company's reasonable projected CX&O O&M expenses.

a. Customer Interactions

Customer Interactions is responsible for the ownership and execution of the various channels of customer interactions. 5 TR 2145. The work of the Customer Interactions group includes five program areas: Digital Customer Operations ("DCO"), Customer Contact Center, Business Customer Care ("BCC"), Credit and Assistance; and Analytics & Outreach. *Id.* All five areas are aligned to the larger department goals of (i) providing customers the opportunity to obtain service in their channel of choice, and (ii) continuously improving the customer experience to

allow customers to choose new programs and products to meet their energy needs. *Id.* For these program areas, the Company is projecting $25.4 million of O&M expenses for the test year ending February 28, 2026, as shown on Exhibit A-130 (SQM-2).

Staff witness Klocke recommended an expense adjustment to the Credit and Assistance program. Specifically, Ms. Klocke argued that $571,961 for the Collection Agency Services portion of the CARE O&M expense, as well as $159,118 for the Theft–Field line item for the CARE O&M expense should be disallowed for the test year. 5 TR 3729-3730. The Company partially disagrees with Staff's proposed adjustments.

As a general matter, the Company believes that Staff's proposed adjustments are unrelated to the CARE Program and that Staff's recommendation is to the Credit and Assistance Program. This Program holds the Company's Collection Agency Services and Theft-Field departments. 5 TR 2185. Thus, none of the proposed adjustments should be to the CARE Program.

Starting with Staff's proposed adjustment of $159,118 to the Theft–Field O&M expense, the Company believes that this is inappropriate. Staff's adjustment was based on a partially correct interpretation of certain Company audit responses. See Exhibits S-13.7, S-13.8, and S-13.9. Company witness McLean explained:

> "At the time of case development, the Revenue Recovery--Field team and Theft—Field were, in fact, two different departments with similar but disparate responsibilities. After testimony was filed in the instant case, the Revenue Recovery-- Field team and Theft--Field team merged into one team. As evidenced in U21585-SA-CE-099 (Exhibit S-13.7), this resulted in a negative variance ($(111,909)) in Revenue Recovery-Field Line item and a positive variance ($159,118) in Theft-Field line item at the time the Staff audit data was submitted. The delta between the two variances of $47,000 is an increase in labor expense." [5 TR 2186.]

Thus, these costs are reasonable as they reflect the funds required to support the team that completes physical theft investigations and disconnections, and the Company requests that the $159,118 related to the Theft–Field O&M expense be approved.

With respect to Staff's recommendation related to Collection Agency Services, the Company agrees with the adjustment. While the Company continues to overall support the actions and related costs associated with collection activities, it agrees to remove the $571,961 based on the results of its RFP for collections services. 5 TR 2187.

Attorney General witness Coppola proposed a general disallowance to the Company's Customer Interactions O&M expense recommending removal of $2.6 million in expenses based on the comparison of actual O&M expenses for Customer Interactions for each of the four quarters ending June 2024. 5 TR 2859. Mr. Coppola argued that the quarterly expense information shows that the Company's actual expense for Customer Interactions for 12 months ended June 2024 is $22.7 million, which is $1.3 million lower than the 2023 expense and $2.6 million lower than the projected test year expense. 2 TR 2860. Thus, he concluded that the Company's forecasted expense should be removed and the level of Customer Interactions O&M expense for the projected test year should be set at $22.7 million.

As a general matter, the Company believes that the Attorney General's proposed adjustment should be modified from $2.6 million to $2.1 million based on the Company's concession of $571,961. This is because the Collection Agency Services expenses falls within the Customer Interactions O&M expense category. 5 TR 2187. Nevertheless, Mr. Coppola's proposed disallowance is also inappropriate as it fails to recognize that there was a reorganization in the business. This reorganization shifted people and costs both within different parts of the customer organization, as well as to the IT organization. All of the same work is being completed

at the projected costs. 5 TR 2187. The actual expenses relied on are artificially low due to the shifting of expenses. Company witness McLean explained:

> …the Company shifted all data and website related work to the IT organization. This reduced the Analytics and Outreach costs by $532,000, and the Digital Customer Operations O&M by $439,600 for the projected test year. None of these costs were included in the IT O&M expenses and still represent the necessary costs to operate these functions regardless of the reorganization. In addition, the reorganization included a shift of various functions that were being included as part of Customer Interactions that now fall within Billing and Payment. This represents a shift of $368,000 of O&M from Customer Interactions to Customer Billing. [5 TR 2188.]

These costs are reasonable because even when accounting for the Company's concession of $571,961, and the inclusion of cost that were impacted by the Company reorganization, the total projected cost of $24.8 million is approximately $716,000 higher than the historical test year, which is less than the cost of inflation. Thus, the Company is requesting approval of Customer Interactions O&M expense of $24.8 million.

b. <u>Billing and Payment</u>

Billing and Payment uses customer feedback to ensure payment processes are consistent and simple and customer bills are timely, accurate, and easy to understand. 5 TR 2158. The Billing and Payment work is divided between the Customer Payment Program and the Customer Billing Program. The Company is projecting approximately $10.0 million of O&M expenses for the test year ending February 2026. As shown on Exhibit A-130 (SQM-2), this represents a decrease in O&M expenses of about $5.7 million from the $15.7 million expended in 2023. 5 TR 2158. Accordingly, the Company is requesting approval of $10.352 million in expenses for Billing and Payment.

7. Corporate Services O&M Expense

References in the Record: Foster, 5 TR 1718-1741; Exhibits A-71 (MJF-1), A-72 (MJF-2), A-73 (MJF-3)

Company witness Foster testified concerning the Company's test year Corporate Services O&M expenses. 5 TR 1721-1730. Mr. Foster explained the nature of the expenses and the areas that are included within Corporate Services. The Company incurred certain Corporate Services expenses on behalf of both the electric and natural gas businesses of Consumers Energy, and the Company applies appropriate methodologies to allocate these costs. 5 TR 1723-1724. After applying these allocations, the Company's projected electric utility portion of the total adjusted test year Corporate Services O&M expense was $29,155,000. Exhibit A-72 (MJF-2). The adjustments include costs removed in the normalizations line including a reduction of $19.8 million for the 2023 Voluntary Separation Program and $5.2 million for the one-time consultant expense. 5 TR 1724, Exhibit A-72 (MJF-2), lines 14 and 15, column (n). The Company then applied an assumed rate of inflation to project Corporate Services O&M based on the Consumer Price Index ("CPI") which considers factors specific to pricing of goods and services, such as the cost of food, energy, and housing. 5 TR 1724-1725. The CPI is 2.4% for 2024, 2.2% for 2025, and 2.2% for 2026. *Id*. The reasonableness of the Company's Corporate Services expenses is supported by S&P Global Market Intelligence ranking Consumers Energy's 2022 Administrative and General costs (excluding pension and benefits) the second lowest out of the 65 companies ranked on a cost-per-customer basis for electric utility companies with more than 500,000 customers. Exhibit A-73 (MJF-3).

a. Insurance Costs

References in the Record: Foster, 5 TR 1722, 1738-1741; Exhibit A-72 (MJF-2); Coppola, 5 TR 2862-2863; Exhibit AG-1.42

Mr. Foster sponsored Exhibit A-72 (MJF-2) which includes the Company's insurance expense for electric operations. This cost element is specifically related to Consumers Energy's electric property and liability insurance to cover the business including property damage, director and officer's liability insurance, public liability insurance, workers' compensation insurance, fiduciary liability insurance, and fidelity insurance. 5 TR 1722. Exhibit A-72 (MJF-2), column (n), line 3, includes a projection of $25.9 million for the Legal, Ethics, Regulatory, and Risk area, which includes the projected insurance expense.

Attorney General witness Coppola's recommendation to remove $6 million from the Company's test year O&M is misaligned with what the Company has requested in this case. 5 TR 2862. Mr. Coppola places the Company's forecasted insurance expense as $16.6 million, referencing the Company's discovery response provided as Exhibit AG-1.42. *Id*. However, this was not the amount the Company projected for the test year insurance expense.

Calculating a compound rate of change using historical data and applying the rate of increase for the test year, Mr. Coppola calculated a forecasted insurance expense of $10,475,000 for the test year and requested the Commission include a reduction of $6 million from the difference between the amount he believes the Company used and the number he calculated. *Id*. The Company's actual projection for the insurance expense that was included in the test year is $9,846,634 as shown in Exhibit A-242 (MJF-7), which is lower than (although close to) the Attorney General's projection. 5 TR 1739. Company witness Foster discussed the expense in his direct testimony, explaining the adjustment made for insurance distributions including the removal for actual distributions received in 2023, which was replaced with the five-year average, and

showing how that resulted in the $9.1 million that the Company used for insurance distributions. 5 TR 1725.

While the Company's response in Exhibit AG-1.42 did indicate a $16.6 million projected insurance expense for the test year, that amount represents a forecast the Company uses for planning purposes. This was not the amount included in this case as the Company's projected test year expense. 5 TR 1740. Accordingly, the Attorney General's adjustment should not be adopted because a $6 million adjustment would lower the Company's insurance O&M request down to about $3.8 million for the test year, whereas the Company's actual projection for O&M in the test year of $9.8 million is already below Mr. Coppola's projection of $10.5 million.

8. Information Technology O&M Expense

References in the Record: Kandan, 5 TR 1854-1856, 1865-1867, 1957-1959,1965, 1968, 1970, Exhibits A-87 (SK-4), A-89 (SK-7), and A-92 (SK-10); Hansen, 5 TR 3695-3696, Exhibit S-10.1

As explained when discussing the Company's proposed capital investments, the IT Department's costs are driven by the Company's Digital Plan that guides its technology investment decisions for operations, as well as the Company's Reliability Roadmap that guides its affordable investments in a modern, reliable, and safe distribution system. 5 TR 1854-1855. At the same time, the Company is investing in technology to protect its customers from cybersecurity threats. 5 TR 1855-1856, 1865-1866. Besides the capital that the Company invests in these critical projects, it also incurs O&M expenses to support these projects. As Mr. Kandan explained, "Investments O&M is used by the Company to fund the O&M portion of upgrade projects, asset refresh projects, and technology investments that are needed to provide the new capabilities for internal business units and customers." 5 TR 1865.

In 2023, the Company allocated $7,471,000 in O&M expenses to the IT Department for its work supporting the electric business. 5 TR 1867; Exhibit A-87 (SK-4). The Company expects

to allocate $9,987,000 in O&M expenses in 2024; $8,709,000 in 2025; and $1,415,000 for January and February of 2026 to the IT Department for its work supporting the electric business. For the projected test year, the Company expects to allocate $8,672,000 in IT O&M expenses. 5 TR 1867; Exhibit A-87 (SK-4).

The Company's proposed IT O&M expenses are needed, well supported in testimony, and should be approved. Staff's proposed disallowances to the Company's test year O&M expenses, which are discussed below, should be rejected.

a. Business Continuity – Program Management Tool

The Business Continuity - Program Management Tool – project will allow the Company to link departments to the essential functions they support and perform necessary analysis before, during, and after critical IT processes and essential functions are disrupted, allowing for a more efficient response to minimize downtime. 5 TR 1957; Exhibit A-89 (SK-7), page 37. Staff nonetheless proposed reducing the Company's projected O&M expenses for this project by $115,265 (20% of $576,323) in the projected test year for the same reasons it proposed reducing the Company's projected capital costs for several IT projects. 5 TR 1958-1959, 3695-3696; Exhibit S-10.1. Staff is wrong for similar reasons.

First, the Business Continuity - Program Management Tool – project is in the investment planning stage, which is a more advanced stage of planning than the Rough Order of Magnitude ("ROM") estimates that the Commission has found too imprecise for ratemaking purposes. 5 TR 1958. Subject matter experts projected the costs based on their knowledge of similar past projects for internal labor costs and vendor bids for contractor costs. 5 TR 1958; Exhibit S-10.2. Unlike capital, the Company does not have the opportunity to recover the O&M expenses in a future case. 5 TR 1958. And since Staff did not dispute the need for the project, 5 TR 1958-1959, the Company should be allowed to recover amounts it reasonably expects to spend.

Second, like the Company's forecasted IT capital project costs that Staff proposed reducing, Staff did not request all the information it needed to evaluate the Business Continuity - Program Management Tool – project's costs. 5 TR 1960. Staff admitted that it did not have "capital software, labor, or contractor costs" for this project and did not say it specifically asked for this information – only that it asked generally for the basis of the Company's cost estimates. 5 TR 3695-3696. Without this information, Staff arbitrarily classified the Business Continuity - Program Management Tool – project as a Class III AACE project, concluding that the Company's estimate could be as much as 20% too high. 5 TR 1950. With the information now on the record – between the Company's direct and rebuttal testimony and exhibits – there is no reason for Staff to dispute, or the Commission to reject, the Company's projections.

Although unmerited, if Staff's proposed disallowance is adopted, the amount should at least be adjusted. As Mr. Kandan testified, "The projected electric allocation O&M expenses for this project are $36,429 (10 months of $14,708 and 2 months of $145,030) for the projected test year," and if the Commission adopts Staff's proposed disallowance against the weight of the evidence, "electric projected O&M expense disallowance of $7,286 (20% of $36,429) would be the correct disallowance amount." 5 TR 1961.

For these reasons, Staff's proposed adjustments to the Business Continuity - Program Management Tool – project's O&M costs should be rejected or, at a minimum, reduced.

b. <u>Enterprise Risk Management</u>

The Enterprise Risk Management project will allow the Company to be more proactive and efficient in managing enterprise risk by centralizing plans to identify, manage, and mitigate risk. 5 TR 1731-1732, 1959; Exhibit A-89 (SK-7), page 67. Staff nonetheless proposed reducing the Company's projected O&M expenses for this project by $91,779 (20% of $458,896) in the projected test year for the same reasons it proposed reducing the Company's projections for the

Business Continuity - Program Management Tool – project. 5 TR 1959, 3695-3696; Exhibit S-10.1. Staff is wrong for the same reasons. See discussion *supra* (discussing the Business Continuity - Program Management Tool – project); 5 TR 1960 (Company witness Kandan's testimony specifically refuting Staff's proposed disallowance for the Enterprise Risk Management project).

Although unmerited, if Staff's proposed disallowance is adopted, the amount should at least be adjusted. As Mr. Kandan testified, "The projected electric allocation O&M expenses for this project are $36,429 (10 months of $14,708 and 2 months of $145,030) for the projected test year," and if the Commission adopts Staff's proposed disallowance against the weight of the evidence, "the electric projected O&M expense disallowance of $7,286 (20% of $36,429) would be the correct disallowance amount." 5 TR 1961.

For these reasons, Staff's proposed adjustments to the Enterprise Risk Management project's O&M costs should be rejected or, at a minimum, reduced.

c. <u>Product Family Enhancement Projects</u>

As the Company explained when describing the Product Family Enhancements projects' forecasted capital costs, these projects will allow the Company to quickly complete small but important enhancements to existing software for new or improved functionality in response to changing business and customer needs. 5 TR 1961; Exhibit A-89 (SK-7), page 93. The Company must be agile in the current digital environment, and this funding will allow the Company to react in real time to changing business conditions, compliance requirements, and customer feedback. Exhibit A-89 (SK-7), page 93. Despite these benefits, Staff proposed reducing the Company's projected O&M expenses for these projects by 20% as follows:

- Product Family Enhancements – Application Platforms Services Capital – project (although described as a capital project by name, it also includes O&M expenses): A

$61,170 (20% of $305,850) O&M expense reduction for the projected test year. 5 TR 1962.

- Product Family Enhancements – Application Platforms Services-O&M – project: A $25,927 (20% of $129,637) O&M expense reduction for the projected test year. 5 TR 1964.

- Product Family Enhancements – Infrastructure Platforms Services - Capital – project (although described as a capital project by name, it also includes O&M expenses): A $51,856 (20% of $259,282) O&M expense reduction for the projected test year. 5 TR 1966.

- Product Family Enhancements – Infrastructure Platforms Services - O&M – project: A $72,917 (20% of $364,583) O&M expense reduction for the projected test year. 5 TR 1968.

Staff proposed an O&M disallowance for these programs for the same reasons it proposed reducing the Company's projections for its Product Family Enhancements projects' capital costs. 5 TR 1962-1963, 3695-3696; Exhibit S-10.1. Staff is wrong for the same reasons. See discussion *supra* at Section III.A.6.b.vi (discussing the Product Family Enhancements projects' capital costs); 5 TR 1961-1970 (Company witness Kandan's testimony specifically refuting Staff's proposed disallowance for the Product Family Enhancements projects' capital and O&M costs).

The Company will not repeat arguments against Staff's proposed adjustments to the Product Family Enhancements projects' capital costs, which also refute Staff's proposed adjustments to the forecasted O&M expenses for these projects. The capital-cost discussion, however, included an excerpt from Exhibit A-92 (SK-10) specific to capital costs, and the below excerpt from Exhibit A-92 (SK-10) is specific to O&M expenses. It compares historical O&M projections for Enhancements projects with actual spending on these projects, revealing that the Company's projected O&M expenses, which are built into rates, have historically been lower than the amount the Company actually spent on these projects[28]:

[28] The image included below is taken from Exhibit A-92 (SK-10) with the capital portion of the graph omitted.

Line No.	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
				Projected O&M							
	Year	Case No.	Source	2019	2020	2021	2022	2023	2024	2025	2026
1	2019 Total Projected	U-20134	A-84 (JRH-3)								
2	2020 Total Projected	U-20697	U20697-SA-CE-022 Response		4,417						
3	2021 Total Projected	U-20697	U20697-SA-CE-022 Response			332,943					
4	2022 Total Projected	U-20963	A-108 (JDT-7)				775,423				
5	2023 Total Projected	U-21224	A-171 (JMW-6)					1,223,256			
6	2024 Total Projected	U-21389	A-180 (HNW-6)						1,795,993		
7	2025 Total Projected	U-21585	A-88 (SK-6)							1,579,577	
8	2026 Total Projected	U-21585	A-88 (SK-6)								1,609,197
				Actual/Projected O&M							
	Project Name	Case No.	Source	2019	2020	2021	2022	2023	2024*	2025	2026
9	2019 Total Actuals	U-20963	A-108 (JDT-7)	639,004							
10	2020 Total Actuals	U-20963	A-108 (JDT-7)		620,329						
11	2021 Total Actuals	U-21224	A-171 (JMW-6)			1,933,411					
12	2022 Total Actuals	U-21389	A-180 (HNW-6)				2,830,965				
13	2023 Total Actuals	U-21585	A-88 (SK-6)					1,659,882			
14	2024 Total Projected	U-21585	A-88 (SK-6)						2,395,672		
15	Projected to Actual Variance			639,004	615,912	1,600,468	2,055,542	436,626	599,679		

*2024 projected based on 1 month of actuals and 11 months of forecast data

Although unmerited, if Staff's proposed disallowance is adopted, the amount should at least be adjusted as follows:

- For the Product Family Enhancements – Infrastructure Platforms Services - Capital – project, Mr. Kandan testified that $192,686 (10 months of $192,686 and two months of $192,686) in test year O&M expenses are allocated to the electric business for this project. 5 TR 1963. So, if the Commission adopts Staff's proposed disallowance against the weight of the evidence, "the electric projected disallowance of . . . $38,537 (20% of $192,686) O&M expenses for projected test year would be the correct disallowance amounts." 5 TR 1968.

- For the Product Family Enhancements – Application Platforms Services-O&M – project, Mr. Kandan testified that $74,114 (10 months of $74,114 and two months of $74,114) in test year O&M expenses are allocated to the electric business for this project. 5 TR 1965. So, if the Commission adopts Staff's proposed disallowance against the weight of the evidence, "the electric projected O&M expense disallowance of $14,823 (20% of $74,114) for the projected test year would be the correct disallowance amount." 5 TR 1965.

- For the Product Family Enhancements – Infrastructure Platforms Services - Capital – project, Mr. Kandan testified that $115,611 (10 months of $115,611 and two months of $115,611) in test year O&M expenses are allocated to the electric business for this project. 5 TR 1968. So, if the Commission adopts Staff's proposed disallowance against the weight of the evidence, "the electric projected disallowance of . . . $23,122 (20% of $115,611) O&M expenses for the projected test year would be the correct disallowance amounts." 5 TR 1968.

- For the Product Family Enhancements – Infrastructure Platforms Services - O&M – project, Mr. Kandan testified that $208,435 (10 months of $208,435 and two months

> of $208,435) in test year O&M expenses are allocated to the electric business for this project. 5 TR 1970. So, if the Commission adopts Staff's proposed disallowance against the weight of the evidence, "the electric projected O&M expense disallowance of $41,867 (20% of $208,435) for the projected test year would be the correct disallowance amount." 5 TR 1970.

In short, Staff's proposed adjustments to the Product Family Enhancements projects' O&M costs should be rejected or, at a minimum, reduced.

9. Security O&M Expense

References in the Record: Reed, 5 TR 2417-2436, Exhibits A-155 (ESR-3) and A-156 (ESR-4)

The projected O&M expenses for Consumers Energy's Security Operations and Security Investments are shown in Exhibits A-155 (ESR-3) and A-156 (ESR-4), respectively. The Company uses Security Operations O&M expense to provide the required level of operational support for both physical and cyber security; maintenance for security facilities and systems to ensure system reliability, vulnerability assessments, and penetration tests; and fulfillment of all state and federal laws and regulations, perimeter protection, guards, card access, cameras, executive protection, and investigative services. 5 TR 2427. The Company uses Security Investment O&M to fund the O&M portion of security technology upgrade projects, asset refresh projects, and technology investments to provide new capabilities for internal security operations to protect the Company's assets, employees, and customers. 5 TR 2434.

The Company's projected Security Operations O&M expense for the test year is $7.287 million. Exhibit A-155 (ESR-3), line 5, column (f). The Company's projected Security Investments O&M expense for the test year is $1.104 million. Exhibit A-156 (ESR-4), line 12, column (f). No party submitted any testimony proposing disallowances to these amounts. The Commission should approve the Company's security O&M expense amounts as filed.

10. Employee Benefits Expense

References in the Record: Grob, 5 TR 1755–1795; Exhibit A-77 (KKG-1); Exhibit A-78 (KKG-2); Exhibit A-79 (KKG-3); York, 5 TR 3336-3337; Rueckert, 5 TR 3778

For the projected test year, the Company projected a total O&M expense level for employee benefits expense of ($66,656,000). Exhibit A-77 (KKG-1). The projected test year employee benefits O&M expense amount includes: (1) a Pension Plans expense of ($53,469,000); (2) a Defined Company Contribution Plan ("DCCP") expense of $14,967,000; (3) a 401k Employee Savings Plan ("ESP") expense of $12,121,000; (4) an active employee health care, life insurance, and Long-Term Disability ("LTD") insurance expense of $28,218,000; (5) a retiree health care and life insurance expense, or OPEB, of ($50,333,000); and (6) an Other Benefits expense of $4,081,000. Exhibit A-67 (KKG-1).

The Company's Pension Plans and OPEB expenses are determined using actuarial analysis performed annually by an actuary in accordance with Accounting Standards Codification ("ASC") 715. 5 TR 1750. The Pension and OPEB Plans were measured in January for year-end 2023. 5 TR 1759; Exhibits A-78 (KKG-2) and A-79 (KKG-3). The DCCP is part of the benefits package needed to attract and retain qualified and talented employees to benefit customers. The DCCP provides an employer-funded contribution to the ESP. 5 TR 1768. The ESP is a defined contribution retirement savings program funded by both employee and employer contributions. 5 TR 1770.

The active employee health care, life insurance, and LTD insurance expense includes the Company portion of these expense items, with the primary component being health care. 5 TR 1774. The Company developed the projected health care expense considering several factors and trends that were a part of the 2023 and 2024 national health trends/costs survey information provided by Willis Towers Watson ("WTW") actuarial consulting. 5 TR 1774. Based on this

analysis, the Company applied the inflation factors used in this case to the 2023 base expense amount to project health care costs. 5 TR 1775. Exhibit A-77 (KKG-1), page 2, line 4, column (i), represents the annual rate of the inflation factor.

For active employee life insurance and LTD, the Company used inflation factors of 2.4% and 2.2% for 2024 and for year 2025 to reflect expected salary increases, any upward movement in Company-paid life insurance coverage, and increases in premium rates. 5 TR 1778. The Other Benefits expense includes the electric utility benefits labor, the absence management program, the educational assistance program, the employee assistance program, and the Leaving It Better Award ("LIBA") program. 5 TR 1789.

Staff witness Shannon Rueckert and ABATE witness York recommended a disallowance of the LIBA program costs. ABATE witness York contended that the Company's projected test year level of Other Benefits expense should be held at the actual historic 2023 level of $3.213 million due to the increase in LIBA program costs. 5 TR 3336-3337. Staff witness Rueckert recommended removal of LIBA O&M program expense of $795,000 as well as a corresponding disallowance of the capital portion of the LIBA totaling $2,666,000, which consists of $875,000 for the bridge year ending December 31, 2024, $894,000 for the two months ending February 28, 2025, and $897,000 for the test year ending February 28, 2026. 5 TR 3779. The basis for the proposed disallowance is the contention that the program does not present a benefit to customers. 5 TR 3778. The Commission should reject the proposed disallowances.

The LIBA is not a new program. It provides Company employees with additional recognition for going above and beyond everyday expectations to serve the Company and its customers, including supporting operational excellence and customer satisfaction. 5 TR 1791. For example, the LIBA program could award an employee that takes on additional work for an

employee on extended leave or for taking on a project that would require considerable additional work. 5 TR 1794. The extra work performed by these employees receiving the LIBA would allow the Company to avoid the additional costs of hiring more employees or contractors. *Id*.

The added recognition provided under the LIBA program benefits the Company's customers through encouraging increased levels of productivity, reducing employee turnover, reducing costs of hiring new employees and contractors, and improving service to customers. 5 TR 1795. The Commission should approve this reasonable expense that can reduce costs and encourage excellent service to customers.

Additionally, Staff's proposed capital cost reduction for the LIBA program is overstated. Specifically, the Company disagrees with Staff's stated costs for the two months ending February 28, 2025. 5 TR 1795. The amounts presented by Staff would be the 2025 program costs in its entirety. The majority of these costs are already included in the test year amount. The costs associated with the two months ending February 28, 2025 is $149,000. *Id*. The added recognition provided under the LIBA program benefits the Company's customers through encouraging increased levels of productivity, reducing employee turnover, reducing costs of hiring new employees and contractors, and improving service to customers. 5 TR 1795. The Commission should approve the O&M and capital cost for the continuation of the LIBA as a reasonable expense that can reduce costs and encourage excellent service to customers.

11. Incentive Compensation Expense

References in the Record: Conrad, 5 TR 1665-1716, Exhibits A-68 (AMC-1), A-69 (AMC-2), A-70 (AMC-3), A-241 (AMC-4); Stuart, 5 TR 2559-2571, Exhibits A-157 (RMS-1), A-158 (RMS-2), A-159 (RMS-3), A-160 (RMS-4); McMillan-Sepkoski, 5 TR 3752-3760, Exhibits S-15.1, S-15.2; Coppola, 5 TR 2863-2871, Exhibit AG-1.44; York, 5 TR 3334-3335

Consumers Energy requests the Commission to authorize recovery in rates of approximately $2.611 million of the Company's expected Employee Incentive Compensation

Plan ("EICP") costs for the projected test year, as shown on Exhibit A-70 (AMC-3). The Company is not requesting recovery of costs related to incentive compensation for financial metrics for EICP. Included in the removal of the O&M related to financial goals is the removal of the affordability operational measure, although the goal is an operational measure, it is financial in nature and was removed alongside other financial measures. 5 TR 1672.

The $2.611 million expense level consists of the EICP linked to officer incentive compensation, totaling approximately $831,000, and the portion of the EICP linked to non-officer incentive compensation, totaling $1.780 million.[29] 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

References in the Record: Conrad, 5 TR 1669-1716, Exhibit A-69 (AMC-2)

Consumers Energy witness Amy M. Conrad, Director of Compensation Operations, 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.[30] See, generally, 5 TR 1669-1716. Consumers Energy's management believes that the Company 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

[29] While believing it to be a reasonable and prudent expense amount, Consumers Energy is also not requesting recovery in rates of the Company's long-term incentive costs in this proceeding. 5 TR 1673.
[30] Employees who are rated as "under-contributing" or "needs improvement" on their annual performance appraisal are not eligible for incentive compensation. 5 TR 1674.

cost. 5 TR 1675. In setting a reasonable level of compensation, Ms. 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 survey process which relies on valid and reliable data from multiple sources to determine median levels of compensation. 5 TR 1678. Compensation levels are actively monitored, and the Company engages in a rigorous benchmarking analysis of comparable jobs and rates of pay. 5 TR 1678-1680. 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 1680-1681; see Exhibit A-69 (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 1671-1672. 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 1672. The total compensation (base pay plus incentive compensation) is targeted at approximately the market median (50th percentile). 5 TR 1672.

The Company's officer compensation levels are determined by the Compensation Committees of the Boards of Directors of Consumers Energy and CMS Energy. 5 TR 1672. 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 1672. 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. 5 TR 1672. These three components in total are targeted at the median (50th percentile) of the competitive market-based pay. 5 TR 1672.

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 1671-1675. If the Company were to compensate employees at uncompetitive levels of pay, the result would be a less qualified workforce. 5 TR 1673-1674. Consumers Energy has a responsibility to customers to employ a competent workforce that is ready, willing, and able to provide service for customers. 5 TR 1678-1679. Paying competitive wages and salaries is necessary in order to fulfill that commitment. 5 TR 1678.

b. <u>The Structure of Consumers Energy's Incentive Compensation Plan</u>

References in the Record: Conrad, 5 TR 1675-1677, 1683-1693, 1709, Exhibit A-68 (AMC-1)

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 incentive pay (a variable pay component) works. One researcher states, "theory and research show that incentive pay can substantially increase individual and organizational performance and can represent a powerful tool for establishing a competitive advantage within an industry." (Dow Scott, *Incentive Pay: Creating a Competitive Advantage* – WorldatWork Press, 2007). There are many more cases of incentive plans as an effective motivational tool. Group incentive plans can contribute to organizational collaboration and achievement of company goals which lead to benefits for customers. A May 15, 2018, Forbes article entitled "The Key to an Effective Incentive Plan" (Bill Fotsch and John Case) continues to support this theory indicating:
>
> > Incentive plans, by definition, are supposed to affect people's behavior on the job, day in and day out. They incent people to work harder and smarter, to go

> the extra mile, to collaborate with their coworkers, to come up with new ideas to improve some aspect of the business.

People don't work for money alone, but they do respond to incentives.

When properly selected and implemented, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. When goals are challenging yet achievable, employees are motivated to increase productivity and performance to achieve the goal. In addition, incentives increase a company's ability to attract, hire, and retain qualified and motivated individuals. A study by the International Society of Performance Improvement showed that incentive pay programs increase performance by an average of 22.0%. (International Society of Performance Improvement, "Incentives Motivation and Workplace Performance Research and Best Practices," Spring 2002). As stated by the Society of Human Resource Management:

> Research has demonstrated that some human resource programs and initiatives produce a significant impact on performance in organizations (as measured by factors such as quality, productivity, speed, customer satisfaction and unwanted turnover). The two initiatives that consistently showed statistically significant positive results were linking pay to performance and using variable pay. Research has established the potential of variable pay to produce the desired business results. [5 TR 1676-1677; the final paragraph quotes Robert Greene, "Variable Pay: How to Manage it Effectively, Society of Human Resource Management," April 2003.]

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 1682.

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 1689. 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. 5 TR 1685-1686. If the targeted high levels of performance are not achieved, employees' incentive pay is reduced or eliminated. 5 TR 1685. 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 EICP, which is the Company's short-term incentive compensation program, is designed to focus and reward achievement of performance goals over periods of approximately one year or less. 5 TR 1669. The EICP goals are structured to encourage employees to provide reliable energy, customer value, and responsive service to customers, and to do so safely. 5 TR 1689. The EICP Performance Measures for the 2023 historical year are summarized on Exhibit A-68 (AMC-1), which identifies the operational performance and financial performance areas of the EICP and the specific measure adopted for each area. The Company's 2024 EICP is structured similarly. 5 TR 1690. These samples are representative of the costs to be expected in the test year assuming continuation of the same fundamental plan. Consistent with prior Commission orders, the Company is not seeking recovery in rates for the portion of EICP expense attributable to the financial performance measures or for the operational measure related to O&M savings measure, which the Company has determined to be financial in nature. 5 TR 1672, 1689-1690. The non-officer EICP equally weighs the operational and performance measures of safety, reliability, and customer value with the financial measures:

- Half (50.0%) of employees' incentive will be based on the achievement of operational performance measures. (For 2023 and 2024, there are six operational measures.); and

- Half (50.0%) of employees' incentive will be based on the achievement of one financial measure, EPS. Consumers Energy is a vital part of the Michigan economy, and it is important that the utility remains financially strong so that it can provide the utility service that customers expect and deserve; however, Consumers Energy is not seeking recovery of the financial portion of the EICP. [5 TR 1675.]

The goals are the same for the officer EICP, but the weightings are different. 5 TR 1675. Officers are 30% based on the achievement of operational measures and 70% based on the achievement of financial measures. 5 TR 1675.

Banded goals driven by well-established connections between employee engagement and the achievement of outcomes are critical to the business and to customers. 5 TR 1683. Each operational measure has its own threshold, target, and maximum for payout. 5 TR 1693. Ms. Conrad testified that this practice aligns better to market practice and with engaging and motivating performance. 5 TR 1693.

Consumers Energy is seeking recovery of EICP expenses at the 100% payout level. 5 TR 1695. 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 1709. The EICP payout levels (shown on Exhibit A-73 (AMC-1)) are established so that the threshold is at a level of achievement that can typically be met eight or nine times out of every 10 years. 5 TR 1693. Maximum payout is for exceptional performance and is expected to be achieved one or two times every 10 years. 5 TR 1693. Ms. Conrad further explained:

> These levels are to engage the employees in meeting the goals. Employees must re-earn the incentive at-risk portion of compensation each year. If the threshold to achieve a payout were set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in fewer customer benefits. Overall compensation levels, including the EICP at target

> (100%) level that Consumers Energy seeks, are not excessive. [5 TR 1693.]

It is reasonable for Consumers Energy to pay its employees competitive levels of compensation. 5 TR 1693. The structure of the Company's EICP is designed to do that while providing employees a strong incentive to achieve the Company's operational goals.

c. <u>The Achievement of Company-Established Operational Metrics Provides Benefits to Customers</u>

References in the Record: Stuart, 5 TR 2561-2571, Exhibit A-157 (RMS-1)

The operational metrics included in the EICP provide benefits to customers, which significantly exceed the costs related to the incentive portion of compensation. Company witness R. Michael Stuart, Director of Metrics and Strategic Planning, testified that a direct tie exists between the Company's operational incentive plans and desirable benefits for customers. 5 TR 2561. For 2024, Consumers Energy established specific performance measures for non-officer employees, which is balanced to produce safe, reliable, and affordable service while ensuring that the Company is strategically positioned for its customers in the future. *Id*. For example, Consumers Energy has set continuous improvement operational goals related to Employee Safety, Culture, Customer Experience, Electric Reliability, and Methane Emission Reduction. *Id*; Exhibit A-157 (RMS-1).

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. 5 TR 2567. The benefits associated with just three of the Company's operational metrics confirm the Company's conclusion that there are substantial benefits that accrue to the customer. *Id*.

The first metric is employee safety, which would reduce employee safety incidents by 29% as compared to the Company's four-year average. 5 TR 2568. The resulting reduction in lost work days and medical expenses approximates $968,000 of annual direct savings and $656,000 of annual indirect savings for an annual total savings of approximately $1.6 million that will accrue to the benefit of the customer. *Id*. The second metric is distribution reliability. Using cost-per-outage-minute estimates from Berkeley Labs, the 5.0-minute annual average reduction in outage minutes from the four-year historical baseline results in annual economic benefits to the Company's customers in excess of $19.6 million. 5 TR 2568-2569. The third metric is the Company's culture index metric. By reducing employee turnover for employees with four or less years of service by just 2%, the Company calculates that it would avoid costs associated with employee turnover of approximately $7.4 million. 5 TR 2569.

Mr. Stuart also testified about the qualitative benefits of the various EICP metrics. 5 TR 2565-2571. For example, the Customer Experience Index goal focuses on ensuring that when customers contact Consumers Energy, customer needs are met, the interaction is easy for the customer, and the experience is enjoyable for the customer. 5 TR 2565. This results in enhanced productivity (e.g. reduces the number and duration of customer calls, which benefits the Company and the customer) and customer value (e.g. quick, easy, and enjoyable solutions for customer experiences). *Id*. As another example, the Culture Index goals emphasize improving the employee experience and their engagement in their work. 5 TR 2563. Gallup produces a metadata analysis that shows that companies that experience high employee engagement have 10% higher customer loyalty and engagement and 18% more productivity than companies with low engagement. *Id*. Improving culture will reduce employee turnover and improve the Company's ability to affordably service customers. *Id*. The cost of turnover is high, with estimates that losing

an employee can cost a company 1.5-2 times the existing employee's salary as the organization shifts to additional attraction and lost productivity. 5 TR 2563-2564. For a third example, the Company's Methane Emission Reduction goal focuses on protecting Michigan's environment and supporting ambitious net-zero carbon emission goals at both the state and federal levels as well as worldwide. 5 TR 2566. By achieving the Company's goal, Consumers Energy will reduce its methane emissions by more than 10,000 metric tons. 5 TR 2566. Mr. Stuart testified that it is the equivalent of removing about 55,000 vehicles from the road for a year or preserving more than 300,000 acres of forest. 5 TR 2566-2567. Reducing those emissions will support limiting global emission increases which have been attributed to increased storm activity globally as well as here in Michigan. 5 TR 2567.

Mr. Stuart testified that there is a direct tie between the design of the EICP operational goals and desirable benefits for customers. *Id*. Mr. Stuart explained that the costs of the EICP will, at a minimum, be commensurate with the programs' costs. 5 TR 2568. Utilizing an allocation of 60% for electric customers, the quantitative benefits that Mr. Stuart calculated equate to annual savings for electric customers of $25.0 million, far exceeding the total costs of the EICP allocated to electric customers. 5 TR 2570.

Mr. Stuart testified that EICP is the reason that these benefits have been and are being realized. 5 TR 2571. Mr. Stuart testified:

> [T]he design of the EICP is intended to, and does, make it significantly more likely that these customer benefits will be achieved through the improvement in the areas of focus identified by the EICP goals. By placing a portion of employees' market-based compensation at-risk, they are incentivized to deliver on the EICP goals related to safety, reliability, and employee culture. [5 TR 2571.]

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.

d. Response to Staff, Attorney General, and ABATE Recommended Disallowances

i. The Commission Should Reject Staff's Proposed Disallowance of Incentive Compensation for the Company's Top Five Officers

References in the Record: McMillan-Sepkoski, 5 TR 3757-3759; Conrad, 5 TR 1711-1714, Exhibit A-241 (AMC-4)

Staff witness Theresa McMillan-Sepkoski generally supports Consumers Energy's proposal to include the EICP expense amount related to operational metrics for non-union employees in calculating rates. 5 TR 3757. However, Ms. McMillan-Sepkoski recommended disallowing a portion ($414,700) of the Company's proposed $2.611 million EICP expense amount solely for the portion attributable to the top five Company officers. 5 TR 3757-3758. Staff witness McMillan-Sepkoski argues that the portion of Consumers Energy's EICP expense that is attributable to its top five officers should be disallowed in rates because Staff could not examine the confidential information used by Pay Governance to provide its advice to the Company's Board of Directors. 5 TR 3758-3759. The Commission should reject that recommendation.

First, the Commission should understand that Consumers Energy does not have direct possession of the market information Staff asked for. Company witness Conrad explained in her rebuttal testimony that the market information at issue is maintained as part of a database of public utility and general industry compensation survey data owned by WTW. 5 TR 1711-1712. WTW's Energy Services Executive Database and its General Industry Executive Database contain the most current proprietary compensation data collected through WTW's annual surveys. 5 TR 1712. WTW's surveys are confidential and proprietary. 5 TR 1712. Furthermore, only the information that WTW gathers with respect to the top five executive officers for each Company will ever be

publicly reported through Securities and Exchange Commission ("SEC") filings. *Id*. Ms. Conrad explained that the Company "cannot directly access the disaggregated and not-publicly-disclosed data in the Willis Towers Watson databases because it could potentially subject the Company to a claim that the Company's compensation practices violate antitrust laws." 5 TR 1712. In other words, Pay Governance allows the Company to gain the benefit of WTW while simultaneously functioning as a shield to protect the Company from potential anti-trust liability. Pay Governance can review the most current information that would put Consumers Energy in legal jeopardy.

The Company engages Pay Governance, an independent compensation consultant, to provide the Company's Compensation Committees with information about the market to help guide compensation decisions. *Id*. Pay Governance uses the WTW database as part of its consulting function, with permission of WTW and CMS Energy, in order to develop its recommendations. *Id*. One part of the value that Pay Governance provides to the Company is its ability to extract discrete peer group data from WTW's databases and apply its own proprietary aging and regression analysis in order to help the Company develop an understanding of how its compensation recommendations compare to the company's peer group without ever exposing the Company to the non-public disaggregated information. *Id*.

In the Company's most recent electric rate case order, Case No. U-21389, the Commission agreed with Staff in adopting essentially the same disallowance proposed here for the Company. In that case, the Company may not have made it sufficiently clear why it cannot access and share the data Staff requested in the case. In light of the additional information provided in this case about the legal reasons Consumers Energy cannot directly possess the information, the Company asks the Commission to reconsider that decision and allow the Company to continue

recovering the reasonable and relatively small amount of EICP costs for its top five executive officers.

Ms. Conrad testified that Consumers Energy is contractually prohibited from sharing the third-party's market median information requested by Staff. 5 TR 1713. The WTW survey sources are produced solely for use by database participants. 5 TR 1712. Pay Governance has written consent from both WTW and CMS Energy to use the surveys on CMS Energy's behalf. *Id*. Pay Governance is prohibited from using or reproducing the database and survey reports prepared by WTW. *Id*.

Because the Company operates in a regulated environment, it generally seeks to include terms in its vendor contracts wherever possible to ensure that the Commission and other parties will have access to information that will be needed as part of regulatory proceedings. However, in some cases, particularly where the product the vendor is selling is solely or mainly comprised of proprietary intellectual property, it is not feasible to obtain terms allowing the Company to share that sensitive and valuable information. If the Company insists on such terms, it may lose access to the information entirely where vendors value their commercially valuable data more than the prospect of turning away one of many potential customers. Even if a vendor were willing to allow the Company to share the information with other participants in its cases, the vendor would likely demand a higher price for permitting such dissemination, which increases the risk of access to their data by their competitors. Either way, insistence on such terms would not be beneficial to customers.

This is particularly true where the information is not really needed in the case. Here, the parties have the sworn testimony of Company witness Conrad explaining that the Company does utilize such market information to target officer compensation at the 50th percentile. 5 TR

1711. There is nothing in the record to suggest that Ms. Conrad has been untruthful about that fact. Furthermore, Ms. Conrad provided Staff with an alternative set of data using publicly available information for the same peer group of companies that Pay Governance used so that Staff could have independent support for Ms. Conrad's testimony that the top five officers' pay was in line with the Company's 50th percentile target. 5 TR 1711; Exhibit A-241 (AMC-4). As Exhibit A-241 (AMC-4) shows, all of Consumers Energy's top five officers except two are paid below the average and all but one are paid at or below the 50th percentile compared to comparable officers at peer companies in terms of both Annual Incentive Compensation and Total Direct Compensation. Two are below the 25th percentile. Exhibit A-241 (AMC-4). The Company acknowledged that the alternative data does not "perfectly represent" the non-public data that Pay Governance used to provide its advice to the Company's Board of Directors (5 TR 1713-1714), but that does not mean that it has no value to independently confirm that the compensation for Consumers Energy's top five officers is consistent with the goal of targeting the 50th percentile of the Company's peers. The data provided "a valid comparison of the compensation of the highest paid through the 2nd, 3rd, 4th, and 5th highest paid named officers compared to the Company's compensation peer group." 5 TR 1714. The information provided to Staff supports Ms. Conrad's testimony. Unless the Commission disagrees with the philosophy of trying to target officer compensation to the 50th percentile, there was ample information provided in this case to support the reasonableness of the compensation for the Company's top five officers.

The Commission should reject Staff's rationale for disallowing the portion of the EICP expense amount attributable to the top five officers in this case, particularly when keeping in mind that the Company is already asking for less than the full expense that it will incur to pay incentive compensation for officers and other employees during the test year.

ii. The Attorney General's Criticisms of the Company's Incentive Compensation Amounts Are Without Merit

References in the Record: Coppola, 5 TR 2866-2868, 2871; Conrad, 5 TR 1669-1672, 1698-1700, 1706-1710; Stuart, 5 TR 2570;

Attorney General witness Coppola argued that the Commission should allow no more than $1.3 million of the $2.6 million proposed by Consumers Energy for EICP in this case. 5 TR 2871. He generally claims that EICP does not benefit customers, and he criticizes several features of the Company's EICP program. The Commission should reject Mr. Coppola's position.

Mr. Coppola's argument that the EICP does not benefit customers is incorrect. The Attorney General's claim ignores the fact that, even including incentive compensation, Consumers Energy's employees are being paid at market level. 5 TR 1669-1672, 1710. Company witness Conrad explained that a wide body of research supports the view that, when properly selected and implemented, as has been done with the Consumers Energy plans, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. Customers unquestionably benefit from the services provided by the Company's employees, and customers will lose those benefits if the Company paid compensation below market levels, which would induce the most qualified and talented employees to seek opportunities elsewhere. 5 TR 1686-1670.

Importantly, the costs for the EICP are not over and above the reasonable level of employee compensation. Company witness Conrad testified that the incentive compensation amount is not a "bonus", or a "profit-sharing plan", or pay in excess of the reasonable compensation level. 5 TR 1700, 1710. To the contrary, as Mr. Conrad explained, the Company has decided to make a certain portion of its reasonable compensation level at risk. 5 TR 1697. This provides motivation for employees to strive for the total level of compensation by providing world class performance and seeking to contribute to the achievement of operational performance measures. *Id*. Additionally,

the EICP provides the above-discussed qualitative and quantitative benefits to customers. As Company witness Stuart stated, "the quantifiable customer benefits equal $25.0 million far exceeding the total costs of the EICP allocated to electric customers." 5 TR 2570. There is no support for Mr. Coppola's general assertion that the EICP does not benefit customers.

In addition to that more general claim, Mr. Coppola mainly took issue with three aspects of the Company's EICP presentation in this case. Mr. Coppola questioned the propriety of including objectives like the Company's methane emission reduction goal in EICP because, in his view, most employees have little impact on achieving those metrics. 5 TR 2866-2867. Ms. Conrad responded in rebuttal testimony that it is necessary and appropriate for a large organization, such as Consumers Energy, to establish broad goals and objectives that are communicated to all employees as matters that are important to the success of the organization. 5 TR 1706. Although she acknowledged that some employees will be in a better position to influence whether particular goals and objectives are met, Ms. Conrad explained that having every employee linked to a set of common customer-focused objectives is an effective method for emphasizing the importance of customer value and service. 5 TR 1706-1707. She testified that having common goals and objectives (i) provides clear communication of Company goals, (ii) encourages employees to support each other and work together for common goals, and (iii) provides a scorecard with a focus on corporate-wide goals that benefit customers. 5 TR 1707. Finally, Mr. Coppola fails to acknowledge that the Commission has approved recovery of the portion of EICP attributable to the operational goals for many rate cases now, including EICP goals of a similar (and even the exact same) type of broad corporate goal.

Second, Mr. Coppola took issue with the Company's change to individual banding for the goals in EICP, claiming that it would allow "mediocre performance" to be rewarded even if only

a single metric is achieved. 5 TR 2868. However, Ms. Conrad pointed out in her rebuttal that his claim is incorrect. She explained that structuring the payout to consider performance of each goal individually "ensures that employees have an independent motivation to achieve each goal regardless of whether another goal may be off target to meet payout levels during the year." 5 TR 1708. Ms. Conrad explained that this removes any potential mis-incentive to "give up" on one goal just because another may have become unlikely to be achieved. *Id*. According to Ms. Conrad, each goal has the ability to earn an EICP payout on its own achievement. So, contrary to Mr. Coppola's claim, every goal remains important, and employee motivation to attain each goal individually remains high. *Id*.

Furthermore, Mr. Coppola's argument once again overlooks the fact that employees' total compensation, including incentive compensation, is set to the market median. That means that, if the Company achieves the target level for nearly every goal but misses target level performance on even a single goal, the total employee compensation for that year will be below market level. 5 TR 1669-1672. Accordingly, the Company's incentive compensation structure does not reward mediocre performance as Mr. Coppola claims. 5 TR 1708-1709. The Attorney General also failed to recognize that, under the old structure that Mr. Coppola apparently preferred, employees could be paid an incentive up to and even above the threshold level for all of the goals as a group as long as the Company achieved roughly 60% of the goals. That means that the old system paid out 100% or more of incentive compensation even on the goals that were not achieved. Under the new system, employees got no incentive compensation for any goals that were not achieved. The new system is a much more appropriate system for ensuring that employees are <u>not</u> rewarded for failure. It is exactly the opposite of what Mr. Coppola claimed.

Third, Mr. Coppola claims that the Company's EICP goals are too heavily weighted toward financial measures. 5 TR 2867. However, that claim ignores the fact that the Company is not seeking recovery in rates for any of the EICP expense amount attributable to financial objectives—those costs are to be borne by shareholders. 5 TR 1707. The Company is seeking rate recovery related only to a small fraction of its EICP expense, which is solely related to the Company's operational metrics. *Id*. The operational metrics are designed to emphasize operational performance criteria in areas that are critical to the Company's utility business and customers. *Id*.

Mr. Coppola also noted some additional problems that he takes with other measures in the EICP, the co-mingling of electric and gas for performance measures and that the Company continues to pay salary increases each year well above the rate of inflation. 5 TR 2868. First, the Company has combined operations, and the Accounting Department allocates the incentive expense between electric and gas based on several factors. 5 TR 1707-1708. Only the electric portion of the expense is represented in this case as the Company has done many times in the past. 5 TR 1708. Contrary to what Mr. Coppola claims, the Company does appropriately segregate the costs between the businesses. 5 TR 2868. Second, Ms. Conrad explains that labor costs should not be held to the rate of inflation because inflation is a measure of rising prices for goods and services in the economy as a whole whereas compensation is specific to a particular geographic market as a "going rate" for its jobs. 5 TR 1709. The Company's compensation is designed to be competitive and rewarding for talent and not just to match inflation. 5 TR 1710. The problems Mr. Coppola alludes to with EICP measures are not justified in the record. The Company appropriately segregates the costs of EICP between electric and gas businesses and the Company's compensation is appropriately tied to competitive labor rates rather than inflation.

To justify the specific amount of Mr. Coppola's proposed disallowance, he claims – with no support – that "[i]t is probable that the company may fall short of achieving 100% of the performance measures." 5 TR 2871. Therefore, Mr. Coppola's proposed disallowance is tied to the amount of EICP expense the Company would incur if it only achieved the lower threshold level of performance for all of its operational performance measures. *Id*. However, Mr. Coppola's own testimony refutes the claim that it is "probable" that the Company will not achieve at least the 100% payout level under its EICP program. Mr. Coppola testified that, over the last five years, non-officer employees have received incentive payouts as a percentage of target of 123% in 2018, 111% in 2019, 139% in 2020, 77% in 2021, and 117% in 2022. 5 TR 2864. History shows that the Company's EICP payout has exceeded the 100% payout threshold almost every year (except one). In fact, the Company's EICP payout in 2023 also exceeded 100%. Recall that the Company's shareholders absorb all of the EICP expense for the financial measures and for any portion of the operational measures that exceed 100%. 5 TR 1698-1699. Mr. Coppola's stated reason provides no legitimate justification for reducing the Company's proposed EICP expense amount of $2.611 million in this case.

For the forgoing reasons, the Attorney General's proposed disallowances are without merit and the Commission should reject them.

iii. ABATE's Recommendation's for the Company's Incentive Compensation Amounts Are Without Merit

References in the Record: York, 5 TR 3334-3336; Conrad, 5 TR 1698, 1708, 1716

ABATE witness York argued that the Commission should reduce the Company's test year request by $1.306 million for EICP in this case. 5 TR 3336. ABATE's claims mostly mirror Attorney General witness Coppola's claims, primarily arguing that it is not reasonable for the Company's EICP expense to be based on an assumed payout at 100%, the methane emission

reduction goal should not be included, and that pay banding is an insufficient incentive for employees to improve operational performance. 5 TR 3334-3335. As stated earlier, the Company's EICP payout has exceeded the 100% payout threshold almost every year (except one) and any cost in excess of the target is absorbed by shareholders. 5 TR 1698. For efficiency purposes and improved service, the Company combines operations as one organization and for that reason the EICP contains gas and electric measures. 5 TR 1716. Lastly, the Company disagree that the thresholds for achieving its goals are low, creating insufficient incentive for employees to improve operational performance due to the pay banding. 5 TR 3335. As explained above, the EICP is part of overall compensation, maximum payout is common market practice, and structuring the payout to consider performance of each goal individually "ensures that employees have an independent motivation to achieve each goal regardless of whether another goal may be off target to meet payout levels during the year." 5 TR 1708, 1716. ABATE's arguments were largely reiterative of the Attorney General's, and for the reasons explained above, ABATE's proposed disallowances are without merit and the Commission should reject them.

e. <u>Conclusion</u>

References in the Record: Conrad, 5 TR 1676-1678, 1700

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 best 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 1700. 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 1676-1678. 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 continue its practice of approving recovery of the portion of EICP expense attributable to the Company's operational goals in rates.

12. Demand Response O&M Expense

References in the Record: McLean, 5 TR 2162-2180, Exhibit A-131 (SQM-3)

The Company's test year O&M costs for its residential and business DR programs are around $34.5 million. 5 TR 2163; Exhibit A-131 (SQM-3). The test year O&M expenses for the C&I DR Program is $21,274,000 and the test year O&M expense for the residential DR Program is $13,262,000. Exhibit A-131 (SQM-3). These DR programs were discussed above in Section III.A.8 of this Brief and were fully supported by the testimony and exhibits of Company witness McLean. 5 TR 2162-2180. The projected O&M expense supports the Company's DR programs which provide a lower cost, flexible capacity resource that can be used to ultimately reduce costs paid by customers. The Company's projected O&M costs for its DR programs should be approved.

13. Uncollectible Expense

References in the Record: Foster, 5 TR 1727-1729; Exhibit A-74 (MJF-4)

To calculate the Company's projected test year amount of uncollectible accounts expense, Mr. Foster used a three-year historical average Bad Debt Loss Ratio of cash basis uncollectible accounts expense to electric service revenue for the years 2021, 2022, and 2023. 5 TR 1727-1728. This ratio was then applied to the test year electric service revenue plus surcharge revenue to arrive at the test year uncollectible accounts expense amount of $18,997,890. Exhibit A-74 (MJF-4), page 2. This method for calculating the uncollectible accounts expense most effectively captures the recent trends of the multiple factors that can impact the expense. 5 TR 1728. The Company also has implemented several mitigation strategies to reduce the expense including turn-

on compliance, prioritizing collection activities on high risk and high volume past due accounts, and using smart meters with automated turn-off capability. 5 TR 1728-1729.

14. Injuries and Damages Expense

References in the Record: Foster, 5 TR 1729-1730; Exhibit A-75 (MJF-5)

Mr. Foster testified in support of the Company's electric injuries and damages expense and sponsored Exhibit A-75 (MJF-5), which summarized the Company's total 2019 through 2023 actual electric injuries and damages expense and projected injuries and damages expense through the test year. Mr. Foster described the electric injuries and damages expense to include liabilities that arise in the normal course of Company business for various types of items, such as: (i) compensation for damaged trees and crops; (ii) restoration of driveways, lawns, and fences; and (iii) accidents and lawsuits (up to an insurance deductible per occurrence). Workers' Compensation costs are included in injuries and damages along with associated internal legal costs. 5 TR 1730. The Company projected a total of $4,137,956 in electric injuries and damages expense for the test year based on a five-year average of actual expense for the years 2019 through 2023 plus inflation. 5 TR 1729-1730.

15. Inflation Rates

References in the Record: Aponte (adopted by Myers), 4 TR 397, Exhibit A-13 (JCA-42), Exhibit A-43 (RTB-4); Myers, 4 TR 448-450, Exhibit A-264 (HJM-13)

Company witness Myers recommended adopting inflation factors of 2.4% for 2024, 2.2% for 2025, and 2.2% for 2026. 4 TR 397. These inflation factors were forecasted by S&P Global Market Intelligence and reported in the October 2023 edition of its publication *U.S Economic Outlook*. *Id*.

MNSC witness Bandyk recommended reducing these inflation rates by a productivity factor ranging from 0.61% to 0.70% to "simulate the effect of productivity improvements on

Consumers Energy's costs." 5 TR 2945. Mr. Bandyk proposed that these "productivity factors" be applied to all costs in Exhibits A-13 (JCA-42) and Exhibit A-43 (RTB-4). *Id*. The Commission should reject the proposed application of a "productivity factor" to the Company's projected O&M costs. Mr. Bandyk's recommendation to apply a blanket productivity factor reduction to all of the Company's O&M expenses fails to recognize that (1) not all O&M expenses are projected by the Company by applying an inflation rate, and (2) productivity gains were already reflected in the Company's projection of test year O&M expenses. 4 TR 448.

Exhibit A-13 (JCA-42) provides a summary of inflation and labor merit increases included in O&M projections and the amounts that were projected using methods other than inflation (i.e., "Other Adjustments"). When applying these Other Adjustments, which in total resulted in a reduction to the projected O&M expense in the test year, the Company's projected O&M costs for the test year are 2.75% lower than the actual 2023 costs. 4 TR 448; Exhibit A-13 (JCA-42), line 25, comparing columns (c) and (i). Many of the Company's witnesses included reductions to their projected O&M exhibits in their exhibits that are referenced in Exhibit A-13 (JCA-42), column (b), as well as a corresponding explanation in their respective testimony. 4 TR 449. As one example, Company witness Blumenstock explained that the Company has implemented focused cost reductions that have impacted both the 2023 actual expense and the projected test year expense, which primarily include headcount reductions during 2023. 5 TR 1497. Other Company witnesses detail cost-savings efforts, and the Company provided additional examples in response to discovery. 4 TR 449-450, Exhibit A-264 (HJM-13).

The Commission should reject any proposal to reduce inflation rates to apply "productivity factors" because the Company has already considered productivity or other cost reductions in its

O&M projections, and its projected test year total O&M expense is in fact less than the 2023 total expense.

D. Depreciation and Amortization Expense

References in the Record: Myers, 4 TR 407; Exhibit A-13 (JCA-51), Schedule C-14; Exhibit A-259 (HJM-8)

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. 4 TR 407. Book depreciation expense was developed by applying the functional composite book depreciation rates to the average projected test year depreciable plant balances. *Id*. The adjustment on Exhibit A-13 (JCA-51), Schedule C-14, line 28, increases depreciation expense from the historical period due to new investment. *Id*. The Company revised its originally filed depreciation expense based on certain adjustments to the Company's originally filed revenue deficiency. See Exhibit A-259 (HJM-8).

The Commission should reject Staff's proposed depreciation expense. Staff's proposed depreciation expense is based on Staff's proposed adjustments to the Company's projected plant-in-service. 5 TR 3542. The Company's disagreement with specific proposed adjustments is discussed elsewhere in this Initial Brief. The Commission should approve the depreciation and amortization expense as presented in Appendix C of the Company's Initial Brief.

E. Taxes

References in the Record: VanBlarcum, 5 TR 2589-2600; Exhibit A-13 (JCA-45), Schedule C-8; Exhibit A-161 (BJV-1); Exhibit A-259 (HJM-8); Exhibit A-162 (BJV-2); Exhibit A-13 (JCA-46), Schedule C-9; Exhibit A-13 (JCA-47), Schedule C-10; Exhibit A-13 (JCA-44), Schedule C-7

1. Property Tax

Company witness Brian J. VanBlarcum, Tax Director in the Company's Corporate Tax Department, testified on behalf of the Company concerning the property tax rate. Mr. VanBlarcum estimated that the 2025 property tax for the electric business will be $265.6 million. 5 TR 2592; Exhibit A-161 (BJV-1), page 1, line 1. For the test year, the property tax expense was prorated for March 1, 2025 through February 28, 2026 using a monthly budgeted sales percentage applied to the 2025 and 2026 estimated annual property tax expense amounts. 5 TR 2595. This resulted in a prorated electric property tax expense of $254.1 million and ultimately a property tax rate of 0.011553991. 5 TR 2339-2340; Exhibit A-161 (BJV-1).

While no party challenged the method that Mr. VanBlarcum used to calculate electric property tax expense, Staff presented a different total property tax amount of $245.122 million. Exhibit S-3, Schedule C-1, line 8. The Company does not oppose the method Staff used to calculate the property tax expense. But for reasons discussed elsewhere in this Initial Brief, the Company disagrees with several of Staff's expense assumptions.

Consumers Energy requests that the Commission adopt a property tax amount of $249,353,000, as shown on Appendix C, line 7, column (d). The difference between Consumers Energy's filed position and its position in this Initial Brief is due to changes to the Company's projected capital expenditures, as shown in Appendix B. The Commission should approve the Company's requested amount.

2. Federal, Michigan, and Local Income Taxes

The Company's original position for its projected Federal Income Tax ("FIT") expense was $65.636 million. Exhibit A-13 (JCA-45), Schedule C-8. During the course of the proceeding, the Company adjusted the projected FIT expense to a total FIT of $72.172 million. Exhibit A-259 (HJM-8), line 11, column (d). Staff presented a FIT expense of $77.737 million. Exhibit S-3, Schedule C-1, line 12. The Company does not oppose the method Staff used to calculate its FIT expense, but for the reasons discussed elsewhere in this Initial Brief, the Company does oppose several of Staff's expense assumptions which impact the FIT expense. Consumers Energy requests that the Commission adopt Consumers Energy's calculation of FIT expense in the amount of $72.172 million, as shown on Appendix C.

In Exhibit A-162 (BJV-2), page 1, Mr. VanBlarcum calculated the test year excess deferred federal income taxes included in this proceeding as approved in Case No. U-20309. The Company also proposed to refund an additional $4,153,000 ($8,707,000 after gross-up for taxes) of excess deferred taxes recorded as of year-end 2021. 5 TR 2597; Exhibit A-162 (BJV-2). "Overall," Mr. VanBlarcum explained, "the Company reduced Federal Income Tax Expense for the test year by $35.961 million to reflect the amortization periods and amounts discussed above." 5 TR 2598.

Moving on to the State Income Tax ("SIT"), the Company initially forecasted that its total SIT for the projected test year would be $35.925 million. Exhibit A-13 (JCA-46), Schedule C-9. In rebuttal, the Company adjusted its projected SIT expense to $37.649 million. Exhibit A-259 (HJM-8), line 10. Staff projected that the total SIT expense would be $42.590 million. Exhibit S-3, Schedule C-1. As with the FIT expense, the difference between the Company's and Staff's SIT expense relates to differences in expense assumptions. Consumers Energy requests that the

Commission adopt the Company's SIT expense in the amount of $37.649 million. See Appendix C. The Company's SIT expense has not changed since it filed rebuttal testimony.

Concerning local taxes, in its direct case, the Company forecasted that its total Other (or Local) Taxes would be $1.238 million in the projected test year. Exhibit A-13 (JCA-47), Schedule C-10. In rebuttal, the Company adjusted its projected Other Local Taxes expense to $1.291 million. Exhibit A-259 (HJM-8), line 9. Staff's calculation of the Other Taxes expense is $2.279 million. Exhibit S-3, Schedule C-1. As with the FIT and SIT expense, the difference between the Company's and Staff's Other Taxes expense relates to differences in expense assumptions. Consumers Energy requests that the Commission adopt the Company's Other Taxes expense of $1.291 million, as shown on Appendix C. The Company's Local Tax expense has not changed since it filed rebuttal testimony.

3. General Taxes

The Company's filed position for projected Payroll and Other General Taxes was $37.974 million. Exhibit A-13 (JCA-44), Schedule C-7. The Company did not adjust its projected General Taxes in rebuttal. Staff's calculation of General Taxes was also $37.974 million. Exhibit S-3, Schedule C-1. Consumers Energy requests that the Commission adopt the Company's total General Taxes expense of $37.974 million, as shown on Appendix C.

F. Allowance for Funds Used During Construction

References in the Record: Myers, 4 TR 408; Exhibit A-13 (JCA-48), Schedule C-11; Exhibit A-259 (HJM-8)

AFUDC is an accounting convention that recognizes the costs, both interest and equity, of financing certain construction projects. 4 TR 408. The criteria for applying AFUDC to a construction project requires on-site construction activities of more than six months duration and an estimated plant cost (excluding AFUDC) in excess of $50,000. *Id*. Consumers Energy

originally calculated a test year jurisdictional AFUDC level of $17.033 million. Exhibit A-13 (JCA-48), Schedule C-11. Due to modifications made in rebuttal testimony, the Company reduced its AFUDC expense to $9.740 million. Exhibit A-259 (HJM-8). The Commission should approve the AFUDC level as presented in Appendix C of the Company's Initial Brief.

G. Calculation of Adjusted Net Operating Income

References in the Record: Exhibit A-259 (HJM-8); Exhibit S-3, Schedule C-1

Total operating revenues of the Company are $4,933,998,000 as shown in Appendix C, line 3, column (d); Exhibit A-259 (HJM-8). After expenses, Net Operating Income ("NOI") is $720,490,000. Appendix C, line 13, column (d). Adjusting for AFUDC leaves an adjusted NOI of $739,230,000. Appendix C, line 15, column (d). Staff's proposed adjusted NOI is $739,230,000. Exhibit S-3, Schedule C-1. The Commission should approve the Adjusted NOI as presented in Appendix C of the Company's Initial Brief.

VI. 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 of $255,433,000. The calculation of this deficiency is summarized in Appendix A.

VII OTHER ISSUES

A. Distribution Investment Recovery Mechanism

References in the Record: Myers, 4 TR 360, 374-380, 438-441, 453-492, Exhibit A-151 (HJM-2); Kelly, 5 TR 919-920; Kenworthy, 5 TR 2669-2673; Coppola, 5 TR 2783-2784; Denzler, 5 TR 3002-3005, Exhibit CUB-35; Dauphinais, 5 TR 3296-3298; Cira-Reyes, 5 TR 3510-3513; Evans, 5 TR 3860-3861

In the U-21389 Order, the Commission approved a two-year IRM subject to revaluation to determine whether the IRM should continue beyond the second year. 5 TR 374. The IRM

mechanism includes a planning meeting to provide transparency on planned spending and to receive stakeholder feedback on the plan, and a separate annual reconciliation proceeding to compare the amount of capital spending included in the IRM with the actual capital spending in that period. 4 TR 375. The Company will return the revenue requirement of any underspend to customers. *Id*. At the time of the filing of this case, the first year of the approved IRM had just begun, and thus the Company did not request to extend the duration of the IRM. *Id*. However, Consumers Energy is proposing to increase the capital spending in the second year of the IRM to align with the capital spending that is approved in this case for the programs that are included in the IRM. 4 TR 374-375.

In the IRM approved in Case No. U-21389, the amounts approved to be included in the IRM total $49.326 million, with $36.880 million in LVD Lines Reliability, $8.973 million in Resiliency, and $3.473 million in System Protection. As discussed in Section III.A.1 of this Initial Brief, the Company is proposing to increase the capital spending in these three distribution programs and include the following amounts in Year 2 of the IRM: $260.802 million in LVD Lines Reliability, $12.623 million in Resiliency, and $5.201 million in System Protection. 4 TR 377.

This alignment of Year 2 of the IRM with the spending projected for these programs in this case will maximize customer benefits. 4 TR 378. The Reliability Roadmap details the Company's distribution investment plan to improve reliability in the face of increasingly severe weather, addressing asset deterioration, maintaining asset health, and hardening assets against severe weather. *Id*. The IRM will provide for recovery of these select distribution capital spending programs and will provide customer protections and additional collaboration and review. 4 TR 378. Customers benefit from the certainty of these reliability and safety improvements, and the

reconciliation process ensures that customers do not pay to support investments if they are not actually made. *Id*.

The proposed increase in the spending included in the IRM demonstrates the Company's commitment to improving the reliability and resiliency of the system and will ensure that this spending occurs. 4 TR 379. The IRM reconciliation process will provide a strong incentive for the Company to avoid shifting this spending between programs. All of these benefits are maximized by increasing the amount of capital spending included in the IRM to match the spending included in the IRM programs in this case. *Id*. If the Commission does not approve the full capital spending for these programs in the IRM, base rates will need to be adjusted to recover the revenue requirement of any capital spending that is not included in the IRM. 4 TR 380.

Staff, the Attorney General, MNSC, ABATE, UCC, and CEO argued that the Commission reject the proposed increase in Year 2 IRM expenditures. See 5 TR 2669-2673, 2783-2784, 3002-3005, 3296-3298, 3510-3513, 3860-3861. The Commission should reject these arguments. Failing to match Year 2 of the IRM with the amounts approved in this case for those programs in the IRM would result in a portion of the test year capital spending collected through base rates and the remainder collected through the IRM mechanism. 4 TR 438. This would confuse the IRM process because it would be challenging to determine the portion of spending that should be applied to the IRM versus the portion that should be included in base rates. *Id*. Accordingly, the Company supports including the approved capital amounts for LVD Lines Reliability, Resiliency, and System Protection in Year 2 of the IRM. *Id*.

Attorney General witness Coppola argued that "uncontrolled spending" should not be approved in the IRM before the subprograms "have been fully vetted in a rate case and have progressed past the initial year of implementation." 5 TR 2784. UCC witness Sergio Cira-Reyes

also expressed concern as to whether the IRM review process is a sufficient replacement for rate case review. 5 TR 3513. The Company's proposal is to match Year 2 of the IRM amounts with those approved in the test year in this case. 4 TR 439. Thus, those amounts will have been "fully vetted" in this case and will have received rate case review because Year 2 of the IRM covers the same period as the projected test year in this case. 4 TR 440. In addition, Mr. Coppola is incorrect that the IRM results in "uncontrolled spending" – the IRM has a reconciliation process to address this concern. 4 TR 439.

Some witnesses argued that expansion of the IRM is premature given the IRM was only recently approved and has not yet been evaluated. See 5 TR 2671, 3005, 3297-3298. Staff also argued that there should be no additional funding in the IRM while review of the Liberty audit is ongoing. 5 TR 3861. These arguments do not support rejection of the Company's proposal to include the approved program expenditures in Year 2 of the IRM.

The Company is not proposing an expansion of the already approved IRM, but only that Year 2 of the IRM matches the approved amounts for those programs in this case. 4 TR 440. This alignment allows the IRM to be consistent with other findings in this case and avoids confusion that could result if these updates are not made. 4 TR 440-441. And even if the Liberty audit results in the Company adjusting spending amounts, the IRM mechanism includes a reconciliation process that ensures customers are not asked to support spending that does not take place, while also providing stakeholders an opportunity to understand any changes in spending that occurred. 4 TR 441.

The Commission should approve the Company's proposal for Year 2 of the IRM and match the expenditures approved in the IRM programs in this case with those included in the IRM. This

will ensure that the benefits of the IRM, including the certainty of the reliability improvements and the reconciliation process, will apply to the full amounts approved in the IRM programs.

B. Environmental Justice

1. Environmental Justice and Distribution Planning

References in the Record: Kelly, 5 TR 882-898, 1005-1025, 1036-1039, Exhibits A-115 (MPK-23) through A-117 (MPK-25), A-244 (MPK-28); Kenworthy, 5 TR 2646-2659; Tan, 5 TR 2677-2696, Exhibits CEO-7 through CEO-9; Cira-Reyes, 5 TR 3499-3509

In collaboration with other parties in Case No. U-21224, Consumers Energy agreed that the Company would study reliability performance and hosting capacity on circuits that overlap with EJ communities (those above the 80th percentile on the MiEJScreen Overall Score), and would provide the results in future versions of the EDIIP and future rate cases. 5 TR 882. The Company provided a preliminary analysis in its initial filing in Case No. U-21389 and provided additional analysis as it was completed through discovery and rebuttal in that case. 5 TR 882-883. An EJ analysis was also included in the Reliability Roadmap, at pages 45 through 53 and Appendix B, and as part of the testimony and exhibits of Company witness Kelly in this case. See 5 TR 883.

The Company used the MiEJScreen tool to identify all of the census tracts within its electric distribution service territory with a score above the 80th percentile. 5 TR 883. The Company has compiled reliability data for customers in EJ communities over the past 5 years, and can compare that with other census tracts in the Company's system. *Id*. On average, the data shows that SAIDI in EJ census tracts mirrors the patterns of the overall system and of non-EJ census tracts, but with SAIDI in EJ census tracts consistently better than in non-EJ census tracts and systemwide. 5 TR 884.

In addition to SAIDI, the Company evaluated 11 additional metrics to assess the reliability experience of EJ communities, including CAIDI, SAIFI, CEMI-4, CEMI-7, and CELID-5 (Customers Experiencing Lengthy Interruption Duration), among others. 5 TR 886. With limited

exceptions, these additional metrics also indicate that on average EJ communities experience better reliability than non-EJ communities and the system as a whole. 5 TR 892. It is also worth noting that circuits serving EJ census tracts make up approximately 2.5% of the primary LVD system, and from 2018 through 2023, Consumers Energy directed 3.1% of its reliability investments to circuits serving EJ communities. 5 TR 893. A significantly larger percentage of EJ-serving circuits are on-cycle for line clearing compared to the system as a whole. *Id*.

Of course, individual EJ communities can still face reliability issues, and when faced with frequent or long-duration outages, these customers are particularly vulnerable. 5 TR 894. To address this, the Company incorporated an EJ flag into its Grid Archetypes process. Under the Grid Archetype process, circuits are flagged for various concerns and prioritized for investment based on the flags received. Generally, a circuit that receives two reliability flags is prioritized for investment. 5 TR 894. The EJ flag indicates whether a circuit intersects with an EJ census tract, which counts as one reliability flag that has been triggered. 5 TR 895. Under this process, intersecting with an EJ census tract is not alone enough to prioritize a circuit, but it will prioritize an EJ circuit that previously only triggered one reliability flag. *Id*. For the sub-programs that make use of Grid Archetypes in the bridge period and test year in this case, 7.5% of the total investment will be on circuits serving EJ communities, while EJ census tracts make up approximately 2.5% of the primary LVD system. 5 TR 896.

CEO witness Kenworthy stated that it is unclear whether the EJ flag "fully addresses all areas needing attention or whether the investments are sufficient to close the gaps in service disparity between EJ and non-EJ communities." 5 TR 2651. Mr. Kenworthy also noted that Consumers Energy has not yet completed the regression analysis, that he understands that Consumers Energy has performed some additional analysis and made preliminary findings, and

that he would appreciate if Consumers Energy could clarify its next steps to address any disparities that were identified. 5 TR 2651, 2655.

In the summer of 2024, Consumers Energy performed two different analyses to further understand reliability concerns for EJ communities. 5 TR 1008. First, the Company determined how many individual EJ circuits have poor reliability. 5 TR 1009. This analysis found that, from 2019 through 2023, 118 of the 190 EJ circuits had average SAIDI excluding MEDs that was in the first or second IEEE quartile. However, 72 EJ circuits had average SAIDI excluding MEDs in the third or fourth quartile. 5 TR 1009. This data shows that while systemwide performance of EJ circuits and EJ census tracts may be good, there are EJ circuits that have poor reliability. 5 TR 1010.

The second analysis that the Company performed was to compare each of the 56 EJ census tracts in the Company's service territory, all of which are identified as urban, with five non-EJ urban census tracts that were most similar to the respective EJ census tract considering population size and housing density. 5 TR 1014. The Company then looked at 12 different reliability metrics as part of these comparisons. 5 TR 1014-1015. The results indicated that for most of the metrics, the EJ census tract performed worse on a moderately more often basis. 5 TR 1016. This is another confirmation that there are EJ communities facing poor reliability. *Id*.

To address the issue of EJ communities facing poor reliability, the Company has developed an EJ Resiliency Plan to make targeted investments on EJ circuits with a goal that every EJ circuit has SAIDI including MEDs that is in the second IEEE quartile or better. 5 TR 1017. The EJ Resiliency Plan includes the following proposed investments: $200 million of total investment in Fractionalization; $350 million of total investment in LVD Lines Rebuilds; and $50 million of total investment in other work, including new reclosers, new switches, and additional fuses. 5 TR

1017-1018. Other than the new substations, all of this investment is incremental to what is included in the Reliability Roadmap. 5 TR 1018. The Company is planning to develop a list of detailed projects for the first year of the EJ Resiliency Plan as part of the test year for its next electric rate case, with an intention to spread the investments over a 10-year period. *Id*. If the Commission would like to prioritize these additional investments sooner, the Company can identify up to $10 million in projects for the test year of this case.

Mr. Kenworthy also recommended that the Company and the Commission engage in a collaborative effort to enhance the ICE Calculator, and that the Company should evaluate how it plans and executes storm responses considering EJ and the impact on disadvantaged communities. 5 TR 2658-2659. The Company and the Commission should not undertake an effort to enhance the ICE Calculator because an effort to update the ICE Calculator was launched in June 2022 with an expected release date of ICE Calculator 2.0 in 2024. 5 TR 1019. The Company does not object to further study of how storm response practices impact disadvantaged communities, but notes that it is still working through other analyses and it would present resource challenges to add more analyses at this stage. 5 TR 1019-1020.

CEO witness Boratha Tan recommended that the Company provide a regression analysis that includes disconnections for rate cases and distribution grid plans, with the expectation that the Company provide a regression model before the next rate case. 5 TR 2683, 2696. As Mr. Tan noted, the Company has been collaborating with CEO and Staff on developing a regression analysis and expects that collaboration to result in the design of the regression analysis. 5 TR 1023. The Company is working in good faith to provide the results of this regression analysis in the Company's next rate case, but that will depend on the Company, CEO, and Staff continuing to make good progress on the appropriate regression analysis parameters. 5 TR 1023-1024. As to

whether that analysis should include disconnections, the Company is continuing to collaborate with CEO and Staff on the analysis, and specific components of the analysis should not be dictated in this case. 5 TR 1025. But bringing metrics outside of distribution planning, such as disconnections, into the analysis may make it more complex and difficult to interpret. *Id*.

CEO witness Tan indicated that his analysis showed that while the Company described Grid Archetype 7 as having the worst reliability, Archetypes 5 and 6 had the worst reliability in 2023. 5 TR 2690. The Company's description of Grid Archetype 7 as having the worst reliability is based on historical data. 5 TR 1024. If Mr. Tan's analysis is correct that it was not the worst-performing Archetype in 2023, that simply indicates that in that year, Grid Archetype 7 performed better than Archetypes 5 and 6. 5 TR 1024-1025. The Company will periodically recategorize circuits based on their actual performance. 5 TR 1025.

UCC witness Cira-Reyes indicated UCC's appreciation of the more in-depth EJ analysis that the Company provided in this case, but stated that the analysis provided was still insufficient because the Company did not provide GIS data for intervenors to access and review and because the Company only compared reliability in EJ communities to the system at large. 5 TR 3504. In Case No. U-21389, the Commission required the Company to "develop, with the Staff's input, a clear and repeatable process that allows interested parties to request, safely obtain, and use GIS data." U-21389 Order, page 286. Pursuant to this requirement, the Company is working with Staff to develop a process to provide GIS data to interested parties and hopes to make the relevant GIS data available soon. 5 TR 1036. While the Company is working in good faith to reasonably comply with this requirement, the Company notes that the U-21389 Order did not set a time limit for when the development of the process needed to be complete. 5 TR 1036-1037. As to

Mr. Cira-Reyes's request for a comparison of reliability in EJ and non-EJ communities, the Company provided this additional analysis in rebuttal as discussed above.

UCC witness Cira-Reyes also questioned the Company's assertion that relative level of investment in EJ circuits, considering line miles, is an indication of equitable investment in those circuits. 5 TR 3506. Mr. Cira-Reyes stated that all things being equal, distribution infrastructure that serves more people should receive more investment. *Id*. The Company disagrees. Many other factors contribute to how much investment is needed per line mile. For example, rural circuits that are in dense forests or swamps will likely have higher costs per line mile for a project than urban circuits running along a street. 5 TR 1037.

Mr. Cira-Reyes also argued that the Company's "delay" in providing a regression analysis means that there is insufficient evidence supporting the equity of the Company's reliability investments. 5 TR 3507. As discussed above, Consumers Energy has provided additional EJ-related analysis and is collaborating with Staff and CEO in good faith to deliver a regression analysis. 5 TR 1038. Similar to the GIS data requirement, the Commission did not place a time limit on when the regression analysis needed to be complete (see U-21389 Order, page 286), so it is inaccurate to characterize the lack of a regression analysis in this case as "delay."

UCC witness Cira-Reyes recommended that the Commission require the Company to "delay rate increases for non-essential infrastructure investments" until the Company has provided a way for intervenors to access GIS data, a reliability analysis comparing EJ communities with non-EJ communities, and a regression analysis as ordered in Case No. U-21389. 5 TR 3509. The Commission should reject this recommendation. The Commission provided several requirements in Case No. U-21389 related to EJ with varying, or no, time requirements. See U-21389 Order, pages 285-287. The Company reasonably complied with those that had time requirements, and is

working in good faith to make progress on the others. The U-21389 Order did not suggest that it would deny distribution investment increases until all of the EJ requirements are met, and such a result would unreasonably prevent the Company from delivering the additional reliability benefits to customers as supported in this case. 5 TR 1039.

2. Energy Equity and Affordability

References in the Record: McLean, 5 TR 2196-2197; Thompkins, 5 TR 2575-2586; Kenworthy, 5 TR 2652

CEO contended that Consumers Energy's attention to its EJ communities must expand beyond reliability. CEO witness Kenworthy argued that the Company should begin to assess other factors that contribute to the way EJ customers experience the grid including energy burden and affordability, disconnections, and enrollment in the Company's various programs. 5 TR 2652. Consumers Energy agrees.

Consumers Energy is dedicated to its purpose of world class performance delivering hometown service. 5 TR 2575. This commitment provides a foundation for achieving an equitable clean energy future. In bringing about this future, the Company is engaging with the communities that it operates in and serves to better understand their unique needs and provide platforms for collaboration. *Id*. Company witness Thompkins explained how the Company's understanding of EJ has evolved indicating that:

> Historically, EJ was often understood to relate primarily to the disproportionate impact of pollution on historically disadvantaged communities; this meant that for a utility, the largest EJ concern would have been the locations of its generation facilities. In recent years, EJ has been expanded more broadly, with the incorporation of energy equity, to encompass a more holistic view of community benefits and burdens including distribution investments in historically disadvantaged communities and the associated impacts on affordability and reliability for those communities. As the Company engages with the communities in its service territory, it

> continues to work on further defining its role within the EJ space and what it means for community relationships. [5 TR 2575-2576.]

Company witness Angela Thompkins then details the efforts undertaken by the Company to engage in the communities it serves. 5 TR 2575-2586.

Additionally, the Company is undertaking efforts to work in the EJ space through collaborative efforts. Consumers Energy is participating in the Commission's Energy Affordability and Accessibility Collaborative ("EAAC"), which is working to define and ensure energy affordability, accessibility, and security/self-sufficiency in collaboration with the EWR-Low Income ("EWR-LI") and the Low Income Equity Policy Board. 5 TR 2586. In addition to attending the EAAC Definitions subcommittee sessions to listen to voices of the community and how they define and view energy equity and EJ related terminology, the Company is actively participating in broader EWR collaboratives and workgroups including the MPSC Energy Affordability and Accessibility and EWR-LI workgroups to identify gaps, priorities, and recommendations for increased focus on DE&I initiatives within EWR. 5 TR 2586. These workgroups provide additional areas of collaboration and learning best practices.

The Company further agrees that grid equity involves more than just reliability and employs multiple programs to target grid equity improvement. These include EWR programs in communities who are overburdened by energy costs. 5 TR 2197. Company witness McLean described the Flint Initiative as an example. He said, "The Flint Initiative, for example, invested more than $1 million in 2023, and will continue investments through 2025, installing energy waste reduction technologies in households that would not otherwise be able to afford them, often first addressing health and safety concerns that preclude improvements without remediation." 5 TR 2197. Additionally, the Company has workforce development programs and renewable energy programs that are targeting resources toward low-income communities. 5 TR 2197.

The Company will continue its efforts to better understand EJ communities and its role in supporting just access to energy. This includes coordinating efforts to support grid reliability and affordability, prioritize customer-first processes and technologies to streamline interactions, improve access to clean energy resources, and offer workforce and economic development opportunities in over-burdened communities. 5 TR 2198. These efforts are initial steps to understanding how EJ customers experience the grid.

C. State Reliability Mechanism

References in the Record: Metz, 5 TR 2313-2316, 2328-2330; Connolly, 2 TR 51-52, Exhibit A-59 (LMC-2); Revere, 5 TR 3798-3802

Company witness Metz supported the Company's State Reliability Mechanism ("SRM") capacity charge inputs, cost offsets, and demand. 5 TR 2313-2316. The SRM capacity charge "is a retail rate, designed to recover the incumbent utility's cost of providing capacity service, to whatever type of customer load – bundled or choice" to ensure long-term resource adequacy to all customers. See MPSC Case No. U-18239, November 21, 2017 Order, page 73.

Company witness Connolly explained how she determined the capacity charge. 2 TR 51-52. Ms. Metz provided the inputs to Ms. Connolly's calculation, including the capacity cost offsets. 5 TR 2313-2314. Ms. Connolly's SRM Capacity Charge calculation resulted in $86.88/MW-day. 2 TR 52; Exhibit A-59 (LMC-2). This compares to the SRM Capacity Charge approved in Case No. U-21389 of $76.62/MW-day, $244.80/MW-day in Case No. U-21224, $328.26/MW-day in Case No. U-20963, and $374.95/MW-day in Case No. U-20697. 5 TR 2315.

Consumers Energy is not proposing any changes to the SRM Capacity Charge calculation in this case. The Company proposed changes to the calculation methodology in Case Nos. U-20697 and U-20963, but in both cases the Commission was clear in its direction to re-open the original proceeding in which the SRM capacity charge calculation methodology was established.

5 TR 2315-2316. The Company therefore intends to further evaluate re-opening the original SRM Case No. U-18239 to propose a calculation methodology—one that does not result in a charge that prevents recovery of the Company's full capacity costs and, as a result, unfairly harms full-service customers. 5 TR 2316. Additionally, the introduction of MISO's new Seasonal Construct will also likely require a change to the SRM Capacity Charge current calculation methodology. 5 TR 2316.

Staff witness Nicholas M. Revere recommended that the Commission adopt an alternative SRM calculation. 5 TR 3798-3802. First, Mr. Revere argued that the CONE represents the "proper cost of capacity." 5 TR 3799. Therefore, he recommended a methodology for splitting the Company's production costs between capacity-related and non-capacity-related by essentially assigning all costs above CONE as non-capacity-related. 5 TR 3800. Second, Mr. Revere recommended that the Commission should only recognize energy market purchases beyond the requirements of Consumers Energy's customers as offsets in the SRM calculation. 5 TR 3801. Mr. Revere argues that only such positive revenues should be considered "sales" under the statute. 5 TR 3801.

Consumers Energy does not disagree that the SRM capacity charge needs to be revisited. 5 TR 2329. However, the Company does not agree that CONE is the proper cost of capacity because it does not adequately represent the variety of generation resources that the Company relies upon to serve its customer load. 5 TR 2328. For instance, Company witness Metz explained that PA 235 requires the Company to achieve 50% renewable energy compliance by 2030 and the cost to build a combustion turbine ("CT") does not adequately represent the Company's cost to construct or contract for renewables, especially on a zonal resource credit ("ZRC") basis. 5 TR 2328. The new energy law effectively prohibits the Company to rely upon CTs for serving

customer load in the future due to the requirements to support either clean or renewable energy. 5 TR 2328.

Furthermore, CONE is developed based upon the cost of a CT on a MW basis. 5 TR 2328. However, Ms. Metz testified that MISO accredits capacity on a ZRC basis – not a MW basis. 5 TR 2328. With the new renewable energy requirements, the Company will need to construct additional wind and solar assets and their accreditation is far less than 100% when considering a ZRC basis for meeting capacity requirements. 5 TR 2328-2329. Any change in the calculation methodology must reflect the proper basis for meeting capacity requirements, based on ZRC's, rather than nameplate capacity, based on MW's. 5 TR 2329.

Ms. Metz testified that the Company does not disagree with limiting the market revenue offset to energy market sales above the Company's service requirements. 5 TR 2329. However, any adjustment must also ensure that the Company's customers aren't burdened with the PPA expense without the benefit of the market revenue. 5 TR 2329.

Although the Company does not wholly disagree with Staff's proposed changes to the SRM calculation, the Commission should not order Staff's proposed alternative SRM calculation due to lack of detail in this case and consistent guidance that the SRM capacity charge calculation methodology should be changed by re-opening the original proceeding, Case No. U-18239. 5 TR 2329. The Commission has repeatedly been clear that changes to the SRM methodology should not be considered in the Company's electric rate cases. Various parties, including the Company, have proposed changes to the Company's SRM methodology in Case Nos. U-20963, U-20697, and U-21389. 5 TR 2329. However, the Commission rejected the modifications each time and directed the Company to re-open the original proceeding in which the SRM capacity charge calculation methodology was established, Case No. U-18239. 5 TR 2329-2330.

As a result of the foregoing, the Commission should approve the Company's SRM capacity charge calculation methodology as supported by Company witnesses Metz and Connolly.

D. Defined Benefit Pension/OPEB Volatility Mechanism

References in the Record: Grob, 5 TR 1765-1766; Rueckert, 5 TR 3779

Consumers Energy requested that the Commission continue to permit the Company to implement the Defined Benefit ("DB") Pension/OPEB Volatility Mechanism as authorized in the Commission's Order in Case No. U-21389. The mechanism eliminates the risk of volatility in the expense. Under the proposed mechanism, the Company would annually defer the difference between the DB Pension/OPEB expense included in rates and the actual expense recorded by the Company under ASC 715. 5 TR 1765. The mechanism accounts for the significant potential for large variability in future Pension and OPEB expense because of the sensitivity of the expense to changes in asset returns and other assumptions. If the actual expense is less than the amount approved in rates, the difference is recognized as a regulatory liability and amortized over 10 years starting the following January. *Id.* If the actual expense is greater than the amount approved in rates, the difference is recognized as a regulatory asset and amortized in the same manner. *Id.* No one opposed the adoption of the Company's proposed mechanism, the proposed mechanism was supported by Staff (5 TR 3778), and so the Company requests that it is adopted by the Commission.

E. Demand Response Surcharge

References in the Record: McLean, 5 TR 2168-2170, 2189-2190; Connolly, 2 TR 68-69; Exhibit A-29 (JCA-64); Exhibit A-16 (LMC-6), Schedule F-2.1; Exhibit A-16 (LMC-6); Exhibit A-62 (LMC-9); York, 5 TR 3362-3363

Pursuant to the three-phase regulatory framework for DR that the Commission approved in its September 15, 2017 Order in Case No. U-18369: (i) capital costs are approved in an IRP; (ii) O&M costs are reviewed and approved in the general rate case; and (iii) a reconciliation occurs annually where actual capital spending is reconciled with the amount approved in the IRP and

recovered through a general rate case and actual O&M spending is reconciled with the amount approved and recovered through a general rate case. Pursuant to this process, a revenue requirement specific to DR capital and O&M costs are calculated as part of the rate case. In the DR reconciliation, the actual DR costs for the applicable year are used to calculate the actual revenue requirement, which is then reconciled with the projected DR revenue requirement established in the general rate case. The over- or under-recovery established in the reconciliation proceeding is then held as a regulatory liability or asset until a subsequent general rate case where it is included in rates. DR financial performance incentives are currently carried as a regulatory asset until included in base rates in a subsequent rate case.

The Company is proposing to modify this regulatory framework to separate DR-related costs from the overall revenue requirement and to recover the costs through an all-encompassing DR surcharge. 5 TR 2168. This will simplify and streamline the DR reconciliation process. By the adoption of a DR surcharge, there is the potential to eliminate long lags for the recognition of over-recoveries and under-recoveries in rates and allow for timely and accurate recovery of the performance incentive. *Id*. Additionally, recovering DR costs through a surcharge will allow for more accurate tracking that will result in more accurate reconciliations and ultimately more accurate rates for customers. 5 TR 2169.

The Company proposes that the Commission approve a surcharge to recover all DR related costs. Consistent with the Staff proposal in Case No. U-20963, the Company has calculated a separate revenue requirement for the DR Program inclusive of all DR related capital, O&M costs, and rate credits. 5 TR 2168. Exhibit A-29 (JCA-64) provides the revenue requirement for DR programs as included in this case. Exhibit A-16 (LMC-6), Schedule F-2.1, shows the allocation, by rate class, for the proposed DR surcharge. Exhibit A-62 (LMC-9) provides the development of

the proposed DR surcharge to recover the test year program's revenue requirement. In its proposed DR surcharge, the Company is requesting approval to recover the performance incentive included in Case No. U-21410, the cumulative regulatory liability, and the revenue requirement amount.

The Company's rate design analysis removed the DR revenue requirement from base rates, as shown in Exhibit A-16 (LMC-2), Schedule F-2.1, line 2, and the corresponding DR surcharge to collect the test year DR revenue requirement and customer credits is shown on line 23 of the exhibit. 2 TR 68. Ms. Connolly explained that the DR surcharge shown on line 23 of Exhibit A-16 (LMC-2), Schedule F-2.1, exceeded the DR revenue requirement shown on line 2 of the exhibit. The Company had introduced the DR surcharge concept to recover the program costs, financial incentive, and reconciled balance in Case No. U-20963. 2 TR 68. Staff expressed interest in the surcharge also including the tariff-based bill credits associated with the residential and business DR programs. The $8,572,000 difference between the $50,506,000 revenue requirement and the $59,078,000 recovered through the surcharge are the tariff bill credits. 2 TR 68-69.

While acknowledging that the Company has reformed its proposal from prior cases, in Case No. U-21389, the Commission indicated that there was a lack of agreement between the Staff and the Company on the costs and credits to be included in a surcharge. MPSC Case No. U-21389 Order, page 293. In response to the Commission's Order, the Company met with Staff to align on the DR surcharge methodology. 5 TR 2170.

ABATE opposed the adoption of a DR surcharge. 5 TR 3362. ABATE witness York contends that the proposed surcharge is unnecessary as the costs at issue are not volatile or significant enough to create unreasonably high regulatory balances or cash flow concerns. *Id.* The Company disagrees with ABATE as the adoption of a DR surcharge is reasonable.

The Company's proposed DR surcharge results in accurate DR rates for customers. As proposed, the surcharge will allow for timely refunds of any potential over-recoveries and timely rate recovery for the Company for any potential under-recoveries and the performance incentive. 5 TR 2190. The Company's proposed surcharge will streamline and simplify the reconciliation process, eliminating potentially long lags for the recognition of over-recoveries and under-recoveries in rates, and allow for timely and accurate recovery of the performance incentive. Additionally, including DR costs also allows for more accurate tracking that will result in more accurate rates for customers. *Id*. Thus, the Commission should approve a DR surcharge for Consumers Energy.

F. DR Performance Incentive

References in the Record: McLean, 5 TR 2165, 2191; Coppola, 5 TR 2861

As part of this case, the Company requested approval to recover the DR performance incentive of $6,225,453, which is included in Case No. U-21410, the 2022 DR reconciliation. Along with recovery of the performance incentive, consistent with Case No. U-21410, the Company is recommending the refund of a regulatory liability of $113,136 which is subtracted from the revenue requirement - including interest, the total regulatory liability is $126,558. 5 TR 2165.

Attorney General witness Coppola recommended that the incentive payment amount amounts be updated due to the Commission's Order in Case No. U-21410. After the filing of the rate case, in Case No. U-21410, the Commission disallowed $0.6 million of the incentive payment amount requested by the Company. The Company agreed to this change. 5 TR 2165. Accordingly, the Company requests the proposed DR surcharges, or rates, be adjusted to appropriately collect all amounts related to the 2022 DR reconciliation.

G. Distribution Deferral

References in the Record: Aponte (adopted by Myers), 4 TR 417-420, Exhibit A-27 (JCA-62); Kelly, 5 TR 1005; Evans, 5 TR 3859-3860

The Commission's January 19, 2023 Order in Case No. U-21224 allowed for deferred accounting for the revenue requirement associated with actual 2023 distribution capital spending above the amounts of $167.2 million for New Business, $148.4 million for Reactive Demand Failures, and $55.1 million for Asset Relocations. 4 TR 417. The deferral was capped at $4 million of revenue requirement for calendar year 2023. *Id*. The Commission's U-21389 Order approved the extension of the deferral of the revenue requirement of 2023 distribution capital spending above rate levels until actuals are included in rates. The extension began on January 1, 2024. The capital spending amounts approved in Case No. U-21389 were $165.1 million for New Business, $173.7 million for Reactive Demand Failures, and $54.6 million for Asset Relocations. 4 TR 417. The Company had actual 2023 capital spending greater than the amounts include in rates for all three of the referenced programs. 4 TR 418.

Exhibit A-27 (JCA-62) provides the calculation of the $21.8 million revenue requirement above the 2023 spending approved in Case Nos. U-21224 and U-21389. 4 TR 418. The Company proposes a 12-month surcharge be established to collect the $21.8 million total deferral. 4 TR 419. The Company requests that the Commission approve continuation of the deferral mechanism approved in Case No. U-21389 for the test year in this case and straight-line amortization of the associated regulatory balance. 4 TR 420.

Staff witness Nicholas M. Evans agreed that the 2023 revenue requirement above 2023 amounts was $21.8 million and agreed that amount is reasonable and prudent. 5 TR 3859. Staff witness Evans also agreed with the Company's request for approval of a continued distribution

deferral with four stipulations. 5 TR 3859-3860. Consumers Energy agrees with the proposed stipulations. 5 TR 1005.

H. Regulatory Asset Treatment

1. PowerMIDrive and PowerMIFleet Permanent and Pilot Programs

References in the Record: Myers, 4 TR 409-410; Exhibit A-17 (JCA-52); Exhibit A-18 (JCA-53)

In Case Nos. U-20134 and U-20697, the Commission approved deferred accounting for expenditures associated with the PowerMIDrive and PowerMIFleet pilot programs. The Commission extended this deferred accounting treatment to the permanent programs and reaffirmed the pilot program treatment in its approval of the settlement agreement in Case No. U-21224 and approved the continuation of the regulatory asset treatment in its final order in Case. No. U-21389. 5 TR 409. Exhibit A-17 (JCA-52) provides the calculation of the projected test year amortization expense, and the projected test year average deferred balance associated with the PowerMIDrive Program. Exhibit A-18 (JCA-53) provides the calculation of the projected test year amortization expense, and the projected test year average deferred balance associated with the PowerMIFleet Program. The associated working capital and amortization has been included in the case.

2. Decommissioning and Ash Disposal Costs

References in the Record: Myers, 4 TR 414; Exhibit A-23 (JCA-58), Exhibit A-24 (JCA-59), Exhibit A-25 (JCA-60)

In the Commission's December 9, 2021 Order in Case No. U-20849, the Commission approved regulatory asset treatment for the decommissioning costs for Karn Units 1 and 2 and the ash disposal costs for Karn Units 1 and 2 and the Classic 7 sites. 4 TR 414. The Commission again approved amortization of the regulatory asset of these costs in Case Nos. U-21224 and U-21389. 4 TR 414-415. In the settlement approved by the Commission in Case No. U-21090,

the Commission approved a regulatory asset for the decommissioning of Campbell Units 1, 2, and 3. 4 TR 415. Exhibits A-23 (JCA-58), A-24 (JCA-59), and A-25 (JCA-60) calculate the test year regulatory asset balance and amortization for the Karn Units 1 and 2 decommissioning costs; the Karn Units 1 and 2, Classic 7, and Campbell Units ash disposal costs; and the Campbell Units decommissioning costs. The associated working capital and amortization has been included in the case.

3. Campbell Plants Net Book Value

References in the Record: Myers, 4 TR 412, 450-451; Exhibit A-21 (1 JCA-56), Exhibit A-22 (JCA-57), Exhibit A-30 (JCA-65); Nichols, 5 TR 2524, Exhibit S-1, Schedule A-2

Pursuant to the settlement agreement approved in Case No. U-21090, in the next rate case filed after the conclusion of the IRP case, the actual remaining net book value of Campbell Units 1, 2, and 3 would be removed from plant-in-service and accumulated depreciation accounts and placed into a regulatory asset. 4 TR 412. Exhibits A-21 (JCA-56) and A-22 (JCA-57) calculate the test year unrecovered net book value, regulatory asset balance, and amortization expense for Campbell Units 1, 2, and 3. The associated working capital and amortization has been included in the case. Exhibit A-30 (JCA-65) shows the associated revenue requirement adjustment of negative $6.596 million.

Staff witness Robert F. Nichols II proposed a revenue requirement adjustment of negative $7.708 million applying Staff's proposed cost of capital, and recommended that the adjustment should be updated to reflect the final authorized cost of capital in the case (except with the ROE set at 9% pursuant to the Commission's order in Case No. U-21090. 5 TR 3534. Staff's proposed adjustment is overstated because the Campbell regulatory asset revenue requirement had already been adjusted to reflect Staff's proposed cost of capital when calculating Staff's revenue deficiency of $156 million shown in Exhibit S-1, Schedule A-1, line 8, column (e). 4 TR 451. The revenue

adjustment using Staff's proposed cost of capital should be negative $4.4 million, which is $2.2 million lower than the adjustment the Company developed in Exhibit A-30 (JCA-65). 4 TR 451.

4. Pension/OPEB Volatility Mechanism

References in the Record: Myers, 4 TR 416; Exhibit A-26 (JCA-61)

In Case Nos. U-21224 and U-21389, the Commission approved a Pension and OPEB Volatility Mechanism. Exhibit A-26 (JCA-61) calculates the projected test year regulatory asset and liability balances, and the corresponding amortization expense associated with the mechanism. The associated working capital and amortization has been included in the case.

5. Covert Plant Acquisition Adjustment

References in the Record: Myers, 4 TR 416

The Covert Plant is a natural gas-fired combined cycle generating unit acquired by the Company in 2023. The Company requests approval of a 25-year amortization period for the $371 million acquisition adjustment included in the purchase price of the Covert Plant. 4 TR 416. The adoption of a 25-year amortization period is reasonable as it aligns with the end of the acquisition adjustment for Zeeland, another natural gas-fired power plant owned by the Company, with similar in-service date and useful life. 4 TR 417.

6. Campbell Units and Karn Units Retention Costs

References in the Record: Myers, 4 TR 411; Exhibit A-19 (JCA-54); Exhibit A-20 (JCA-55)

The settlement agreement that the Commission approved in its June 23, 2022 Order in Case No. U-21090 agreed that the Company's 2022 retention costs for Campbell Units 1, 2, and 3 would be deferred through a regulatory asset. This was confirmed in Case No. U-21389. 4 TR 411. In this case, Consumers Energy calculated the test year regulatory asset balance and amortization for

Campbell Units 1, 2, and 3 retention costs and included the associated working capital and amortization in the case. Exhibit A-20 (JCA-55).

Similarly, the Commission ordered regulatory asset treatment for Karn Units 1 and 2 retention costs in Case No. U-20697. 4 TR 411. Exhibit A-19 (JCA-54) calculates the projected test year regulatory asset balance and amortization expense. The associated working capital and amortization has been included in the case.

I. Income Qualified Programs

References in the Record: McLean, 5 TR 2192-2196; Cira-Reyes, 5 TR 3489, 3494; Braunschweig, 5 TR 3817-3828; Colton, 5 TR 3065-3097

In Case No. U-20836, the Commission charged the EAAC with reviewing a report detailing the Low-Income Assistance Credit ("LIAC") enrollment and to discuss the LIAC enrollment assignment and enrollment cap, followed by submitting a report to the Commission. 5 TR 3817-3818. Following that Order, in Case No. U-20757, the Commission reaffirmed its interest in the EAAC's analysis of utilities' RIA/LIAC as fulfillment of MCL 460.11(2) and directed Staff to include analysis of percentage of income payment plan pilots ("PIPP") and Michigan Energy Assistance Program offerings to assist the Commission in understanding current energy assistance offerings. 5 TR 3818. Overall, the workgroup's efforts are focused on providing a comprehensive analysis and diverse, collaborative input to inform utility energy assistance changes. *Id*. During the workgroup, participants can thoughtfully consider how a program is administered, how outreach and customer interactions should be designed, as well as who administers the program. Consumers Energy maintains that the work being undertaken in the various Commission workgroups should be finalized before modifications are made to its various income qualified programs.

1. Summer Protection Plan

In an effort to address the impact of potentially having unsafe temperatures in homes, the UCC argued for the Commission to establish additional measures for customer protection. Specifically, UCC witness Cira-Reyes advocated for the Commission to require the Company to copy its Winter Protection Plan to prevent shutoffs during the summer months of May through September. 5 TR 3489. The Company does not believe that this is necessary at this time.

This UCC's proposal overlooks the fact that the Company already has weather-related protections in place for customers. Consumers Energy has an Extreme Weather Policy in place where the Company does not perform shut offs in extreme weather. Specifically, the policy prevents shut offs in temperatures over 90 degrees, and at 15 degrees or below. 5 TR 2192.

While the Company has a policy in place to protect customers, it does not believe that additional programs should be created until after the completion of the Commission's ongoing workgroups. As indicated above, the Commission currently has ongoing cross functional workgroups that are addressing the role of Michigan utilities as it relates to customers in need of assistance or shut off protections. 5 TR 2192. Participants in the workgroup - which includes state agencies, utility providers, and others – are working to identify and address low-income specific energy issues, energy optimization measures, and create new initiatives that can reduce the cost of the energy burden on Michigan's low income energy consumers and communities. 5 TR 2192.

The Company believes that changes related to income specific energy issues should be addressed by the Commission workgroups. This would allow for broad discussion about the proposed change, as well as discussion regarding the application to all Michigan utilities. 5 TR 2193. This would also allow for thoughtful consideration of the costs associated with this proposed change and the impact it would have on all customers. 5 TR 2193. Therefore, Consumers Energy maintains that the UCC's requested program be denied and that any large-scale changes to

low-income utility programs should be addressed holistically in the Commission's workgroups related to these issues.

2. Percent of Income Payment Program

UCC alleged that the Company should implement a single PIPP that would replace the different mix of programs and credits offered to low-income customers. 5 TR 3494. Mr. Cira-Reyes argued that "A PIPP program would fix a customer's energy charges at a percentage of the customer's income that is considered affordable. Assuming an even split between gas and electric charges, experts state that anything above 3% of income spent on electricity is considered unaffordable. As such, I recommend the Company provide a PIPP program with electricity capped at 3% of income." 5 TR 3493.

As noted by Mr. Cira-Reyes (5 TR 3494-3495), the Company is currently concluding a two-year Commission-approved PIPP pilot. See MPSC Case No. U-21021, February 10, 2022 Order. The pilot started in October 2022 and is currently entering its final phase. 5 TR 2193. After the conclusion of the pilot, the Company will be able to utilize information gained to determine the feasibility of launching PIPP as an ongoing program. *Id*. It would be inappropriate to make any changes to the PIPP pilot until the initial two-year pilot is complete.

Additionally, it would be inappropriate to implement a PIPP to replace the different mix of programs and credits offered to low-income customers at this time. As indicated above, the Commission's EAAC subcommittee/workgroup is ongoing. This workgroup will participate in the evaluation and make recommendations regarding PIPP pilot. The Company believes that this workgroup is the proper venue to holistically review its low-income programs, including PIPP.

3. Residential Income Assistance Credits and Low-Income Assistance Credits

Company representatives participate in the Commission's EAAC subcommittee/workgroup, which is currently assessing utilities' fulfillment of MCL 460.11(2), which authorizes RIA and LIAC. 5 TR 2192-2193. As discussed above, the workgroup's efforts are ongoing and are specifically looking at potential changes to LIAC and RIA.

MNSC recommended reassessing the LIAC and RIA in place. Through the testimony of Mr. Colton, MNSC proposed: (1) to eliminate the RIA credit; (2) to amend and expand LIAC; and (3) to combine LIAC with federal assistance. 5 TR 3073-3097. Additionally, MNSC argued that the LIAC costs should be included in base rates. 5 TR 3078. These recommendations would require sweeping policy and programming changes that should be applied across the industry and would impact more than the Company. 5 TR 2195.

These approaches to changing existing assistance programs, and other policy issues, are being considered in the Commission's Workgroup. This is the appropriate venue to review this type of programmatic change. The workgroup can also have a thoughtful discussion about the proposed changes and a deliberate discussion about recovery of the LIAC funding in rates. 5 TR 2195. As the collaborative is looking at finding a reasonable path forward, it would be premature to make any comprehensive changes to the program at this time.

J. Microgrids on the Distribution System

References in the Record: Kelly, 5 TR 1033-1035; Rafson, 5 TR 2627-2636

GLREA witness Robert Rafson stated that a microgrid for a single property is a nanogrid, that a nanogrid can allow neighbors to share in stable power, and that the Commission "should formally allow nanogrid customers to connect to their neighbors during service outage emergencies." 5 TR 2629-2630. GLREA's recommendation should be rejected. While the

Company has evaluated different potential applications of microgrids, the Commission cannot allow Mr. Rafson's proposed nanogrid concept unless many more details are considered, including whether it would comply with Michigan law and meet important safety requirements. 5 TR 1035.

There would be fundamental safety concerns with encouraging customers to share power with their neighbors. 5 TR 1035. And the owner of a microgrid (or nanogrid) that consists of independently owned distribution lines would be considered a utility under several statutory provisions, and would require a proper certificate or regulatory approval. For example, MCL 460.10q(4) states that "[o]nly investor-owned, cooperative, or municipally owned electric utilities shall own, construct, or operate electric distribution facilities or electric meter equipment used in the distribution of electricity in this state."[31] See also MCL 460.501 and 460.502. A third-party microgrid (or nanogrid) that generates energy in one location to serve customers in another location would also likely be contrary to Commission rules. See R 460.3102(p) and R 460.3411(2).

For these reasons, the Commission should reject Mr. Rafson's proposal that the Commission allow and encourage the development of nanogrids and microgrids.

K. Transmission Coordination with METC

References in the Record: Kelly, 5 TR 1056-1057; Adarkwa, 5 TR 3267-3274

METC witness Kwafo Adarkwa proposed that the Commission require the Company to engage in "substantive discussions with METC to proactively assess the grid for EV charging impacts." 5 TR 3274. The Company is willing to collaborate with METC as needed, and the Company welcomes METC to reach out for such collaboration at any time. 5 TR 1057. METC

[31] While this statute indicates that it does not prohibit "self-service power," Mr. Rafson's proposal does not appear to involve self-service power.

has not shown that the Company has failed to engage in any such collaborative discussions, and there is no need for the Commission to order that these discussions occur.

L. Power for America Training Trust Fund

References in the Record: Kelly, 5 TR 1057; Wright, 5 TR 3466-3469

MSUWC witness Craig Wright discussed the Power for America Training Trust Fund ("P4A"), which was created to provide training support to workers and administer apprenticeship programs. 5 TR 3467. Mr. Wright recommended that the Commission encourage the Company to review utility workforce issues and explore additional investment in P4A. 5 TR 3469. The Company already partners with MSUWC and has partnered with P4A since 2013, and there is an existing contract in place through 2028. 5 TR 1057. MSUWC and Consumers Energy are already free to discuss exploring further investment in P4A, and the Company and P4A (with MSUWC) are currently discussing the development and implementation of new programs. *Id*. There is no need for the Commission to encourage the Company to explore these additional investments.

M. Preservation of Evidentiary Issue

References in the Record: 3 TR 321-325

On October 23, 2024, Staff filed a Motion to Strike specific portions of Company witness Myers' pre-filed rebuttal testimony regarding service restoration expense recovery. On October 28, 2024, Consumers Energy filed a response opposing Staff's Motion to Strike, and MNSC filed a response supporting the Motion to Strike. At the October 31, 2024 evidentiary hearing, the admission of pages 13 and 14 of Ms. Myers' pre-filed rebuttal testimony was argued and considered. See 3 TR 321-325. The ALJ granted Staff's motion, concluding that there is not sufficient time under the rate case schedule to consider new proposals in rebuttal. 3 TR 325. The stricken testimony is shown in the transcript at 4 TR 436-437.

Rebuttal evidence is "broadly defined as that given by one party to contradict, repel, explain, or disprove evidence produced by the other party and tending directly to weaken or impeach the same." *Kirk v Ford Motor Co*, 147 Mich App 337, 345; 383 NW2d 193 (1985). The stricken testimony of Company witness Myers falls within the definition of "rebuttal evidence." Consumers Energy, by this Initial Brief, contends that the ALJ's ruling on the admissibility of pages 13 and 14 of Ms. Myers' pre-filed rebuttal testimony was erroneous, and the Company wishes to preserve its right to contest the ALJ's rulings in future briefing directed to the Commission in this case.

In its direct case, Consumers Energy proposed a SRCSM that would be triggered if the net service restoration spend is below or above the amounts included in base rates. 5 TR 2531. Under this proposal, if the annual service restoration spend is below the amount included in rates, customers will receive a 50% refund of the difference, and if the annual service restoration spend is above the amount included in rates, 50% of the difference will be eligible for deferred recovery. *Id*. The 50% of actual spend amounts above or below the amount included in rates will be recorded in a regulatory asset or regulatory liability, respectively, with the deferred amount reviewed in a future rate case for refund to or collection from customers. 5 TR 1735.

As discussed in Section V.C.3 of this Initial Brief, Staff, the Attorney General, and MNSC submitted testimony disagreeing with the Company's SRCSM proposal. In rebuttal, Company witness Snider presented testimony indicating that the Company's proposed SRCSM should be approved and explaining why the arguments of Staff, MNSC, and the Attorney General witnesses should be rejected. 5 TR 2544-2557. Company witness Myers also provided pre-filed rebuttal testimony in response to these parties' arguments, pages 13 and 14, which offered an alternative proposal that the Commission could consider if there were concerns with the Company's proposal

as originally filed. Under the Company's alternative proposal that was stricken, the Company would defer any amounts incurred for service restoration expense that are above or below the amounts included in base rates for future recovery from or refund to customers. Myers' Pre-filed Rebuttal Testimony, page 14. Ms. Myers' stricken testimony stated that the "request by the Company would be accompanied by support showing conditions faced and the reasonableness of the restoration efforts and associated costs." *Id*.

The Company's alternative proposal offered in Ms. Myers' stricken rebuttal testimony was prompted by and in response to the parties' testimony that the SRCSM should be rejected, and was not something that should have been included in the Company's direct case. It was not "supplemental direct" testimony. In addition, the Company's alternative proposal was not an entirely new proposal that had no connection to the Company's originally proposed mechanism – instead, the Company's alternative proposal merely provided a limited number of adjustments to the Company's original proposal for consideration by the parties and the Commission.

The alternative proposal would have simply removed the 50% of actual spending limitation associated with the deferral and would have committed to the types of information that the Company would provide to support the reasonableness and prudence of its service restoration costs when filing for refund or recovery. Thus, the fact that the alternative proposal came in rebuttal does not support striking the testimony or in any way undermine the parties' ability to challenge the Company's proposal. The parties had the opportunity to review and present testimony responding to the primary aspect of both proposals, which is deferred accounting for the service restoration expense. Pages 13 and 14 of Ms. Myers' rebuttal testimony was proper rebuttal and should not have been stricken from evidence. Consumers Energy preserves its right to take this position before the Commission.

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

A. Cost of Service

References in the Record: Connolly, 2 TR 41-52

Company witness Connolly, Director of Regulated Pricing, presented the Company's COSS by rate class and proposed rate design. Ms. Connolly described the nature of a COSS:

> A COSS is a three-part analysis that quantifies the utility's cost to serve each rate class. The COSS filed in this case serves two primary purposes. First, it identifies and assigns the utility's electric production and distribution costs to the jurisdictional electric rate classes. Second, the COSS is used to determine the contribution of each jurisdictional electric rate class to jurisdictional earnings. [2 TR 45.]

Said another way, the COSS identifies the major activities or "functions" that each cost is incurred to support (functionalization). 2 TR 45. It then categorizes each cost into demand, customer, and energy components according to the primary cost drivers (categorization). 2 TR 45. Finally, it allocates those costs based on each customer class's contribution to causing that cost (allocation). 2 TR 45. The COSS is ultimately used to guide rate design, and the costs assigned to a group of customers should reflect how those customers influence the utility's costs. 2 TR 45-46.

Ms. Connolly presented a test year COSS in the Company's initial filing in this case. 2 TR 48. The Test Year Electric COSS – Version 1 ("COSS Version 1") is summarized in Exhibit A-16 (LMC-1), Schedule F-1. COSS Version 1 made routine updates for historical and test year data including allocation schedule and certain housekeeping updates that were approved in Case No. U-21389. 2 TR 49. The changes to Version 1 of the COSS resulting from the order are:

- The breakout and allocation of battery plant and related costs;

- The breakout of the regulatory asset and amortization expenses for both PowerMIDrive ("PMD") and PowerMIFleet ("PMF") and allocation based on present revenues;

- Removal of the calculation of EIP credits in the COSS and movement/centralization of the calculation in Rate Design;

- Allocation methodologies for surcharges including the Electric Rate Case Deferral, IRM, and DR surcharges;

- Replacement of the current Class Peak allocator with an Alternative Class Peak to allocate demand-related distribution costs; and

- Continued breakout of certain Digital Customer Operations ("DCO") project costs. [2 TR 49.]

Company witness Connolly notes that, consistent with Commission approved methodologies, the rate base associated with the regulatory assets for Karn Units 1 and 2, the Classic 7, and the Campbell plants was functionalized as production and assigned to customers using allocator 220 (i.e. the 4 CP 75-0-25 allocator used for production costs). 2 TR 50. Additionally, the COSS Version 1 reflects the removal of non-jurisdictional revenue as discussed by Company witness Myers and LEDR revenue is reflected in Miscellaneous revenue as indicated in Case No. U-21160. 2 TR 49. The Company is not including any proposals that would necessitate the need for a Version 2 COSS. Thus, the Test Year COSS Version 1 was used for rate design purposes. 2 TR 51. The Company requests that its COSS as filed be approved in this proceeding.

1. <u>Line Clearing Allocation</u>

References in the Record: Connolly, 2 TR 41-42; Denzler, 5 TR 3019

MNSC contended that the Company should adjust the COSS to allocate line clearing costs so that the costs were distributed proportional to the benefits obtained (5 TR 3019) and recommended that the Commission order the Company to prepare a COSS which allocates proportionately the incremental costs of the new line clearing cycle to customer classes based on the incremental benefits to those classes. 5 TR 3021. This recommendation fails to properly understand how costs are assigned in the COSS. The Company's COSS is designed to ensure that

the customers who drive an investment are paying for their proportional use of that investment. 2 TR 82. As explained above, the COSS assigns costs to customers based on how they impact the utility's costs. O&M expenses are categorized into FERC accounts. Then, the allocators are selected in order to target the customers using the Company's facilities driving that cost. 2 TR 82. In the case of the LVD system, residential customers drive a larger share of the investment, so the costs are proportionally allocated to the residential class. Accordingly, the COSS properly assigns line clearing costs.

B. Rate Design

References in the Record: Connolly, 2 TR 54-57, 72; Isakson, 5 TR 3605; Exhibit A-16 (LMC-5), Schedule F-2.0; Exhibit A-16 (LMC-2), Schedule F-2.1; Exhibit A-16 (LMC-3), Schedule F-3.0; Exhibit A-16 (LMC-8), Schedule F-4.0; Confidential Exhibit A-65 (LMC-12)

Rate design requires a balancing of multiple objectives to ensure that rates are fair and efficient. Ms. Connolly testified that, consistent with prior cases, she used four key objectives to inform rate design in this case. The first objective was to adhere to the cost-of-service requirements, with deviations from the COSS in few instances, as discussed below. The second objective was to design rates that encourage the efficient use of the Company's electric system, meaning rates that accurately reflect the type of cost as well as the temporal nature of certain costs, such as the increased cost of providing energy during peak seasons and times of day. 2 TR 54. The third objective was to design rates that promote a favorable business climate, and the fourth was to design stable rates that would provide the Company with a fair opportunity to collect its revenue requirement. 2 TR 54.

Consistent to prior electric rate cases, the Company is recommending five standard adjustments to the assignment of costs across the various rate classes and schedules as part of rate design. The first reflected the difference between the market cost of production capacity collected

from large standby customers taking service under Rate GSG-2 and the embedded cost of capacity allocated to them in the COSS. 2 TR 55; Exhibit A-16 (LMC-2), Schedule F-2.1. The second and third adjustments were for both production energy and transmission costs. 2 TR 55; Exhibit A-16 (LMC-2), Schedule F-2.1. The fourth corrected for an over allocation of substation costs to voltage levels 1 and 2 rates as part of the COSS that was identified in Case No. U-20134. 2 TR 55. The last adjustment reflected the lifeline credits (senior citizen and low-income) that have traditionally been supported by all customer classes. 2 TR 56. This adjustment is not cost justified but based on the Commission's authority to approve special senior citizen and low-income rates.

Ms. Connolly described designing rates to collect Consumers Energy's production costs, as well as the calculation of the LTILRR revenues. 2 TR 56-57. The Company's electric base rates are designed to recover its test year revenue requirement as shown in Exhibit A-16 (LMC-5), Schedule F-2.0, as well as the LTILRR revenues of $99,370,432, as shown in Confidential Exhibit A-65 (LMC-12).

The Company's present and proposed rate design changes are shown in Exhibit A-16 (LMC-3), Schedule F-3.0. The proposed electric rates were calculated to collect the jurisdictional revenue requirement contained in Exhibit A-16 (LMC-5), Schedule F-2.0. Further, the present and proposed electric charges were applied to the billing determinants to calculate the test year revenues shown in Exhibit A-16 (LMC-6), Schedule F-2.1. The monthly bill impacts for each rate schedule are shown in Exhibit A-16 (LMC-8), Schedule F-4.0.

Staff identified an error in the rate design for Rate RSM. It was found that the incorrect customer counts for the RSC and the RIA were applied. 5 TR 3605. Staff witness Isakson indicated that "the Excel model points to the wrong input cells and has the effect of switching the customer counts between the two credits." *Id.* Company witness Connolly agreed with the

correction. 2 TR 72, 74. Accordingly, the Company requests that the Commission approve the Company's as filed rate resign with the modification to correct the RIA and Senior Citizen customer count.

1. Rate Modifications

a. Rate GPD Coincident Peak Energy Provision

References in the Record: Connolly, 2 TR 61-63

For Rate GPD, the Company is proposing a new coincident peak energy provision. This provision would be limited to three customers so that the impact can be evaluated. 2 TR 63. Customers would pay the same On Peak and Off Peak energy charges, customer charges, and distribution charges as a standard GPD customer. 2 TR 62.

Company witness Connolly explained the Company's current method for charging for capacity costs for Rate GPD. Ms. Connolly stated that:

> [c]apacity costs on Rate GPD are collected through an On Peak Billing Demand charge. On Peak Billing Demand is based on the highest On Peak demand created during the billing month but never less than 60% of the highest On Peak billing demand of the four preceding summer billing months (this is generally referred to as a demand ratchet). The On Peak Billing period is defined as 11 AM to 7 PM. There are unique circumstances where customers might run production during the Off Peak hours and avoid the On Peak window to keep costs low. In the event their production was delayed and ran into the On Peak window in the summer, they would be charged for 60% of that On Peak demand for the next eleven months. This can have a huge impact on the bill of a customer that is trying to respond to price signals to keep their bill low. The coincident peak provision is proposed as a solution to help this very specific type of customer. [2 TR 62.]

Under the new GPD coincident peak provision, On Peak capacity and transmission are collected on an energy basis. 2 TR 62. The On Peak capacity and transmission charges were converted to a per kWh basis and would be charged for any usage during the On Peak period. *Id*. This allows a participating customer to use the On Peak period without triggering the On Peak

demand ratchet. This proposed change was unopposed and should be approved by the Commission.

b. Power Factor Credits and Penalties

References in the Record: Connolly, 2 TR 65

Consumers Energy is proposing to change the application of its power factor credits and penalties. This is based on the findings from the report that the Company agreed to undertake in a settlement agreement in Case No. U-21224. 2 TR 65. Company witness Connolly explained the proposed change. She stated that:

> The Company is proposing to compare the average hourly metered kilovolt-ampere reactive hour (kVARh) for the month to the average hourly kVARh at 0.875 lagging power factor. The difference between these two values would determine the average kilovolt ampere reactive (kVAR) demand of underperformance or overperformance for the month. This average kVAR demand of underperformance (penalty) or overperformance (credit) would be subject to a monthly per kVAR charge. The per kVAR charge is calculated so as not to dramatically change what is being applied today. [2 TR 66.]

Calculation of the power factor is shown on Exhibit A-67 (LMC-14). The proposed charges and application of power factor are explained in the applicable tariff sheets as part of Exhibit A-16 (BAG-2), Schedule F-5. This proposed change was unopposed and should be adopted by the Commission.

c. Rate LEDR Facilities Allowance

References in the Record: Connolly, 2 TR 63-64; Isakson, 5 TR 3617-3618, 3623; Dauphinais, 5 TR 3298-3300, 3326

The LEDR was first established by the Commission in Case No. U-21160 and implemented in December 2021. LEDR was recently amended in Case No. U-21646 to update the production charge to reflect the equivalent of CONE. See MPSC Case No. U-21646, June 6, 2024 Order.

In this case, the Company proposes to add a facilities allowance on the rate toward the cost of any incremental distribution investments necessary to serve the LED customer based on the expected margin (non-energy related costs) that would be provided by the customer over the term of the customer's contract. 2 TR 63-64. The Company proposes to calculate the facilities allowance for each prospective Rate LED customer based on the NPV of margin – defined as the non-energy related costs – based on their expected load over the life of the contract. 2 TR 64.

The Company's proposed allowance is due to the fact that when discussing LEDR with customers, potential customers often asked the Company if a facilities allowance is available. This is due to DTE Electric offering a facilities allowance under its Rate D13 XL High Load Factor. 2 TR 64. Thus, to better align with other cost-based large customer rate options in Michigan, the Company requests to add tariff language that would clarify that a facilities allowance would be applicable for customers on the rate. *Id.*

Staff witness Isakson's position was that the LEDR facilities allowance should not include power supply revenue, although he was supportive of using just distribution revenue and the system contribution charge for a facilities allowance. 5 TR 3617-3618. Staff witness Isakson opposed the inclusion of production capacity in the allowance calculation, as the charges only cover the marginal costs of capacity contributed by the addition of a Rate LED customer. *Id.*

Additionally, Staff witness Isakson opposed the facilities allowance being based on the customer's margin for the lifetime of the contract; instead, he supported a facilities allowance that is similar in length to the line extension policy offered to non-Rate LED customers. Accordingly, Staff recommended that the Company propose a facilities allowance that mimics DTE Electric's facilities allowance for its economic development Rate D13. 5 TR 3623.

ABATE witness Dauphinais also discussed the Company's proposal to offer prospective LEDR customers a facilities allowance toward the cost of any incremental distribution investments necessary to serve the customer based on expected sales margins. 5 TR 3298. Mr. Dauphinais states that ABATE supports the proposed change, but only up to the expected system contribution and delivery service revenue of the customer over the term of the customer's contract. 5 TR 3299. ABATE maintained that expected non-energy power supply revenues should not be included in the allowance. 5 TR 3299. This is because the Company has increased the power supply production demand charge due to rising market prices for capacity, and ABATE witness Dauphinais contended that "Rate LED non-energy power supply revenues are likely just sufficient to cover Consumers' incremental capacity and transmission cost to serve a new Rate LED customer." 5 TR 3300. Thus, ABATE cannot support the inclusion of expected LEDR non-energy power supply charges in the determination of the facilities allowance.

After considerations of the arguments made by Staff and ABATE, the Company attempted to address the concerns raised by adopting ABATE's proposal to modify the proposed facilities allowance. This would limit the facilities allowance to the expected system contribution and delivery service revenue in its calculation. 5 TR 75. However, the Company continues to disagree with Staff's proposal to limit the allowance to three years as this provides little benefit to customers.

The purpose of LEDR is to foster large non-data center customer economic development that would not occur but for the rate. The Company recommends adopting its modified proposal, as opposed to rejecting the facilities allowance, as a competitive LEDR, can help attract large companies to Michigan. 2 TR 64. This can provide transformational opportunities such as jobs, tax revenue, infrastructure, new residences, and quality of life improvements. *Id*. As ABATE

witness Dauphinais said, an "[o]utright rejection goes too far in that it unduly handicaps Consumers' ability to pursue large non-data center customer economic development in its service territory at the expense of its existing customers. In contrast, approving the proposed facilities allowance with appropriate limitations to ensure it does not create a subsidy from existing customers to new customers." 5 TR 3326.

2. Customer Charge

References in the Record: Connolly, 2 TR 72-74; Pung, 5 TR 3631- 3633

The Company is proposing maintaining the residential customer charge in this case at $8.00 per month. Staff also recommends maintaining the residential customer at $8.00 per month indicating that this will provide rate stability for the Company's customers. 5 TR 3633.

While the Company and Staff agree on the residential customer charge to be approved, Staff calculated its customer charge using the same methodology as the Company but with historical numbers. 5 TR 3632. Staff witness Mark J. Pung argued that the use of historical cost amounts is appropriate to the uncertainty regarding the test-year cost projections included in the Company's COSS. 5 TR 3632. Staff witness Pung indicated that "[p]rojecting test-year amounts for COSS accounts that are included in the customer charge calculation based upon historical ratios will likely result in costs being included in the charge that should not be and vice versa." 5 TR 3632. The Company disagrees with this approach.

The Company has used the same methods and inputs previously approved by the Commission to calculate the customer costs and charge. 2 TR 73. The COSS and resulting rates are based on projected test year costs and so it is reasonable to consider and use the same costs when evaluating the customer costs and charge. *Id*. The adoption of Staff's proposal causes concern because to calculate the historic customer costs (and charge), the Company would have to prepare a historic COSS. 2 TR 74. This could add significant additional work without any benefit

as both the Company and Staff are proposing the same customer charge. Thus, the Company disagrees with Staff's proposed methodology change.

3. Substation Ownership Credit

References in the Record: Connolly, 2 TR 52; Exhibit A-61 (LMC-4); Exhibit A-16 (LMC-1), Schedule F-1; Pung, 5 TR 3636

A Substation Ownership Credit is given to customers who own their own substations. Exhibit A-61 (LMC-4) provides a calculation of the credit using the same methodology approved by the Commission in Case No. U-18322. This methodology takes the substation costs that have been allocated to GPD, GPTU, and EIP customers on Voltage 1 and Voltage 2 and determines the cost on a per kW basis for each voltage level. 2 TR 52. The calculation follows the same methodology for both voltages using figures from Exhibit A-16 (LMC-1), Schedule F-1, Test Year COSS Version 1 and rate design. 2 TR 52. Staff used the same method as the Company to calculate its Substation Ownership Credits but updated for Staff's revenue requirement. 5 TR 3636. The Company requests that the Commission approve the Substation Ownership Credit.

4. Distributed Generation Credits

References in the Record: Rafson, 5 TR 2625-2626; Connolly, 2 TR 83

In Case No. U-21569, the Commission issued an order seeking comments on the implementation of PA 235, specifically Sections 173 and 177 and related definitions. Section 173 increases the size of Michigan's DG Program from 1% of an electric utility's or alternative electric supplier's average in-state peak load for the preceding five calendar years to 10% of the average in-state peak load for the preceding five calendar years and provides other changes to the DG Program. Section 177 addresses metering and billing associated with the DG Program. During the comment proceeding, the Commission addressed the DG bill credits. The proceeding did not

address how the DG credits are calculated, as that was decided previously, but rather the application of the DG credit in any billing period.

For the comment period, the Commission posed the question of whether Section 177(2) of Act 235 allows for DG customers to offset the entire bill, including separate time-of-use periods, surcharges, and other items that were not historically offset. See MPSC Case No. U-21569 *et al*, July 23, 2024 Order, page 13. In summarizing Consumers Energy's comments, the Commission indicated that:

> Consumers comments that "MCL 460.1177(2) does not change how the DG credit is calculated or the total amount of the DG credit." Consumers' initial comments, p. 3. Consumers states that "the intent of Section 177(2) seems to be that the credit amount that will be applied to a single bill is only limited to the total charges for regulated utility service on the electric customer's bill." Id. However, Consumers comments that under MCL 460.10k, 460.10l, and 460.10n securitization charges occupy a special status. Consumers notes that the right to impose those charges does not belong to the utility but rather to the Special Purpose Entity, because those charges must be remote from the utility for bankruptcy purposes and are nonbypassable. Id., p. 4. Consumers points out that the utility carries out the task of billing for the securitization charge only as a servicer for the Special Purpose Entity. [*Id*. at 13-14.]

Ultimately, in that case, the Commission determined that the new statutory language allows customers to offset the entire bill. *Id*. at 14. The Commission then continued on, holding that:

> The Commission finds that the new language constitutes a requirement that a DG customer be credited for outflow, that the credit appear on the bill, and that the credit be limited to the total charges on that bill. This clearly requires a change from prior billing practices. However, the Commission agrees with Consumers that outflow credits may not be used to offset securitization charges appearing on the customer's bill. This is because the provisions of MCL 460.1177(2) apply to the customer's "supplier of electric generation service." The Special Purpose Entity created under the provisions of MCL 460.10h-460.10o is not the supplier of electric generation service but, rather, the assignee of the securitization property. The right to impose, collect, and receive securitization

charges is part of the securitization property. MCL 460.10j(1)(a). The law provides that:

> The interest of an assignee or pledgee in securitization property and in the revenues and collections arising from that property are not subject to setoff, counterclaim, surcharge, or defense by the electric utility or any other person or in connection with the bankruptcy of the electric utility or any other entity.

MCL 460.10k(1). Further:

> An agreement by an electric utility or assignee to transfer securitization property that expressly states that the transfer is a sale or other absolute transfer signifies that the transaction is a true sale and is not a secured transaction and that title, legal and equitable, has passed to the entity to which the securitization property is transferred.

MCL 460.10l(1). These provisions make clear that, with an approved financing order, the right to impose and collect the securitization charge transfers to the assignee of the securitization property, which is referred to in a financing order as the Special Purpose Entity; thereafter, the utility only acts as a servicer for the Special Purpose Entity. See, MCL 460.10i. Thus, the Commission finds that the DG customer's bill credit may not be applied to the securitization charge on the DG customer's bill. [*Id*. at 14-15.]

The Commission also directed the rate-regulated electric utilities to file an ex parte application for approval of a revised DG tariff consistent with the provisions of Act 235 and its July 23 Order in a new docket no later than September 20, 2024. *Id*. at 22. GLREA disagreed with the Commission's Order and filed a petition for rehearing. The Commission denied GLREA's Petition. MPSC Case No. U-21569 *et al*, October 10, 2024 Order.

In this proceeding, GLREA took the opportunity to once again challenge the Commission's order. It reiterated its argument that the outflow credits for DG customers should be applied to the customers' total bill, including securitization charges. See 5 TR 2625. Additionally, GLREA requested that the Commission reject the Company's September 20, 2024 *ex parte* Application in

Case No. U-21796, in this case. 5 TR 2626. These arguments should be rejected as they are contrary to the Commission's interpretation of the statute and the direction it gave to Consumers Energy.

C. Tariff Issues

References in the Record: Gray, 5 TR 1745-1748, Exhibit A-76 (BAG-1)

The Company recommended several tariff revisions, most of which were undisputed. 5 TR 1745-1748; Exhibit A-76 (BAG-1). Below, the Company addresses the challenges and recommended changes to its proposed tariff revisions.

1. Community Solar

References in the Record: Cira-Reyes, 5 TR 3521-3526; Krause, 5 TR 3877-3879; Gray, 5 TR 1751; McLean, 5 TR 2191; Rafson, 5 TR 2610-2624

GLREA and UCC argued that the Company should implement a community solar program. 5 TR 2610-2624; 5 TR 3521-3526. The Company has not proposed a community solar program in this case, nor does it believe that this is the proper venue for the proposal.

As a general matter, the Company believes that it is more appropriate for a community solar program to be reviewed as part of its Voluntary Green Pricing Program cases. In fact, in its Settlement Agreement approved in Case No. U-21224, the Company agreed to provide a strawman recommendation on community solar in its Voluntary Green Pricing Program. 5 TR 2191. The Company subsequently filed a community solar proposal in Case No. U-21374 on September 22, 2023. Any changes to the Company's community solar program should be addressed in future Voluntary Green Pricing Program filings and should not be addressed here.

To the extent the Commission wanted to consider community solar in this case, a viable proposal has not been presented. Staff witness Kevin S. Krause pointed out that neither UCC witness Cira-Reyes nor GLREA witness Rafson presented evidence in support of any solar costs

or accepted compensation structures in Michigan. 5 TR 3878. Staff witness Krause explained that:

> Without knowing the costs of potential Community Solar arrays, nor the compensation structure that would be to used for these potential programs, it is premature to promise any bill savings whatsoever. In fact, it is possible that to achieve those bill savings a community solar program may need compensation that exceeds anything that exists in Michigan's legal and regulatory framework today or what could be considered reasonable. Without knowing the costs of potential Community Solar arrays, nor the compensation structure that would be to used for these potential programs, the effect on bills is uncertain and should not be understood to be guaranteed. [5 TR 3878.]

Ultimately, the Company is open to collaborating with Staff and other interested parties to consider voluntary solar options for customers which are legal and fair to the Company and all of its customers. 5 TR 1751. No tariff provisions should be approved until the underlying program is appropriately considered. Consumers Energy opposes the creation of a community solar program in this case.

2. <u>Land Lease Tariff</u>

References in the Record: Gray, 5 TR 1751

The Company had expressed an interest in leasing land from Michigan's Department of Natural Resources ("DNR"), intending to use the land to build a utility-scale renewable energy generator. The DNR wished to pay potential future lease agreements with bill credits to help lower the DNR's operating expenses. To facilitate this arrangement, the Company had proposed to add an option to its tariffs to allow customers to apply bill credits as a form of a payment for land leases. In rebuttal testimony, however, the Company withdrew its request for this tariff

amendment. Staff and the MEIU had recommendations and opinions about this tariff amendment, but they mooted when the Company withdrew its request. 5 TR 1751.

3. Power Factor

References in the Record: Gray, 5 TR 1752, Exhibit A-76 (BAG-1); Dauphinais, 5 TR 3310

In Exhibit A-76 (BAG-1), the Company recommended revisions to several tariff pages to update them to reflect a new calculation for power factor adjustments. In response, ABATE recommended that the Company adopt these proposed changes "on a going forward basis, beginning on the date Consumers' final approved rates in this proceeding go into effect . . . ." 5 TR 3310. The Company, however, requires a minimum of six months to configure, test, and implement these changes in the SAP billing system. Also, changes to the power factor calculation must be made on a "bill month basis and cannot be prorated." 5 TR 1752. The Company prefers the first day of the November 2025 billing month as the effective date for the power factor modifications.

4. Self Generation Tariff

References in the Record: Gray, 5 TR 1752

The Company and ABATE agreed to ABATE's proposed revision to Tariff Sheet No. C-59.00 clarifying when the Company can refuse to contract for energy from a Qualifying Facility in certain energy-only contracts. 5 TR 1752.

IX. CONCLUSION

WHEREFORE, for the reasons set forth in this Initial Brief and Consumers Energy Company's testimony and exhibits, Consumers Energy Company requests that the Michigan Public Service Commission:

A. Authorize Consumers Energy to adjust its retail electric rates so as to provide additional revenue of $255.4 million annually above levels established in Case No. U-21389 based on a projected 12-month test year ending February 28, 2026, plus an additional $22 million for the distribution deferral;

B. Authorize Consumers Energy to adjust its existing retail electric rates so as to produce a rate of return on common equity of not less than 10.25%;

C. Approve the proposed Demand Response, Distribution Deferral, and Investment Recovery Mechanism surcharges;

D. Approve the Service Restoration Cost Sharing Mechanism;

E. Approve modifications to the rates, rules, regulations and programs as are described in the Company's testimony and exhibits and in this Initial Brief;

F. Approve the Company's accounting requests and use of regulatory assets or regulatory liabilities, as needed, including those related to (i) the continued deferral of certain distribution capital spending until actual amounts are included in rates, (ii) the Service Restoration Cost Sharing Mechanism, (iii) amortization of the Covert Plant Acquisition Adjustment; (iv) Defined Benefit Pension/OPEB; and (v) the river hydro investments; and

G. Grant Consumers Energy any other request and/or relief discussed in this Initial Brief that is not specifically mentioned in this Section, and grant the Company such other and further relief as is just and reasonable.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Dated: December 3, 2024 By: _____

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APPENDICES
A through D

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Revenue Deficiency
For the Projected 12-Month Period Ending 2/28/2026
$(000)

Case No.: U-21585
Appendix A
Page 1 of 1

Line No.	Description	Source - Adjustments	Company Initial Filing {1}	Adjustments	Company Brief Position Col. (c) + Col. (d)	MPSC Staff Initial Filing {2}	Difference Col. (e) - Col. (f)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Rate Base	Appendix B	15,571,480	(409,694)	15,161,786	14,808,450	353,336
2	Adjusted Net Operating Income	Appendix C	735,242	3,988	739,230	764,418	(25,188)
3	Overall Rate of Return	Line 2 / line 1	4.72%	0.15%	4.88%	5.16%	-0.29%
4	Required Rate of Return	Exhibit No.: A-210 (MRB-19)	6.21%	-0.04%	6.17%	5.93%	0.23%
5	Income Required	Line 1 * line 4	966,300	(31,246)	935,054	878,567	56,487
6	Income Deficiency (Sufficiency)	Line 5 - line 2	231,058	(35,234)	195,824	114,149	81,675
7	Revenue Conversion Factor		1.3381	1.3381	1.3381	1.3381	-
8	Revenue Deficiency (Sufficiency)	Line 6 * line 7	309,174	(47,146)	262,028	152,741	109,288
9	Campbell revenue requirement adjustment	Exhibit No.: A-254 (HJM-3)	(6,596)	0	(6,595)	(4,400)	(2,195)
10	Adjusted revenue deficiency (sufficiency)	Line 8 + Line 9	302,579	(47,146)	255,433	148,340	107,093

Notes

{1} Source: Exhibit No.: A-11 (JCA-27)
{2} Source: Exhibit No.: S-1, Sched. A-1, including post filing correction

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Rate Base
For the Projected 12-Month Period Ending 2/28/2026
$(000)

Case No.: U-21585
Appendix B
Page 1 of 1

Line No.	(a) Description	(b) Source - Adjustments	(c) Company Initial Filing {1}	(d) Adjustments	(e) Company Brief Position Col. (c) + Col. (d)	(f) MPSC Staff Initial Filing {2}	(g) Difference Col. (e) - Col. (f)
1	Total Utility Plant	Exhibit No.: A-255 (HJM-4)	18,800,014	(410,840)	18,389,174	18,022,061	367,113
2	Depreciation Reserve	Exhibit No.: A-255 (HJM-4)	(6,355,195)	8,269	(6,346,926)	(6,340,272)	(6,654)
3	Customer Advances for Construction	Exhibit No.: A-255 (HJM-4)	(60,766)	-	(60,766)	(60,766)	-
4	Net Utility Plant	Sum of lines 1 through 3	12,384,053	(402,571)	11,981,482	11,621,023	360,459
5	Net Unamortized MGP	Exhibit No.: A-255 (HJM-4)	-	-	-	-	-
6	Utility Plant Rate Base	Line 4 + line 5	12,384,053	(402,571)	11,981,482	11,621,023	360,459
7	Working Capital	Exhibit No.: A-258 (HJM-7)	3,187,427	(7,123)	3,180,304	3,187,427	(7,123)
8	Total Rate Base	Line 6 + line 7	15,571,480	(409,694)	15,161,786	14,808,450	353,336

Notes

{1} Source: Exhibit No.: A-12 (JCA-30)
{2} Source: Exhibit No.: S-2, Sched. B-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Net Operating Income
For the Projected 12-Month Period Ending 2/28/2026
$(000)

Case No.: U-21585
Appendix C

Line No.	(a) Description	(b) Company Initial Filing {1}	(c) Adjustments {2}	(d) Company Brief Position Col. (b) + Col. (c)	(e) MPSC Staff Initial Filing {3}	(f) Difference Col. (d) - Col. (e)
1	Sales Revenues	4,762,080	132	4,762,212	4,808,203	(45,991)
2	Other Revenues	171,786	-	171,786	171,786	-
3	Operating Revenue	4,933,866	132	4,933,998	4,979,989	(45,991)
4	Power supply costs	2,374,056	-	2,374,056	2,390,431	(16,375)
5	Other O&M Expense	675,029	(4,449)	670,580	669,324	1,257
6	Depreciation and amortization	771,698	(10,266)	761,433	751,973	9,460
7	Property Taxes	254,100	(4,747)	249,353	245,112	4,241
8	General Taxes	37,974	-	37,974	37,974	-
9	Other (Local) Taxes	1,238	53	1,291	2,285	(994)
10	State Income Tax	35,925	1,724	37,649	42,760	(5,111)
11	Federal Income Tax	65,636	6,536	72,172	78,383	(6,212)
12	Operating Expenses	4,215,657	(11,149)	4,204,508	4,218,242	(13,733)
13	Net Operating Income	718,209	11,281	729,490	761,747	(32,258)
14	AFUDC	17,033	(7,293)	9,740	2,671	7,069
15	Net Operating Income, Including AFUDC	735,242	3,988	739,230	764,418	(25,189)
	Net Operating Income Adjustments					
16	Income Tax Effect of Interest		---- Included in Lines 12, 13, and 14 ----			
17	Interest Synchronization Adjustment		---- Included in Lines 12, 13, and 14 ----			
18	Total Adjusted Net Operating Income	735,242	3,988	739,230	764,418	(25,189)

Notes

{1} Source: Exhibit No.: A-13 (JCA-37)
{2} Exhibit No.: A-259 (HJM-8)
{3} Source: Exhibit No.: S-3, Sched. C-1, including post filing correction

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Strucuture & Rate of Return Summary - COMPANY BRIEF POSITION
For the Projected 12-Month Period Ending 2/28/2026
$(000)

Case No.: U-21585
Appendix D

Line No.	(a) Description	(b) Company Initial Filing	(c) Adjustments	(d) Company Brief Position	(e) Percent Permanent Capital	(f) Percent of Total Capital	(g) Cost Rate %	(h) Weighted Total Cost %	(i) Conversion Factor	(j) Pre-Tax Return
1	Long Term Debt	11,956,226	1	11,956,227	49.09%	40.97%	4.27%	1.75%		1.75%
2	Preferred Stock	37,315	-	37,315	0.15%	0.13%	4.50%	0.01%	1.3381	0.01%
3	Common Equity	12,359,741	-	12,359,741	50.75%	42.36%	10.25%	4.34%	1.3381	5.81%
4	Permanent Capital	24,353,282	1	24,353,283						
5	Short Term Debt	281,156	44	281,200		0.96%	4.28%	0.04%		0.04%
6	Deferred FIT	4,430,290	(290)	4,430,000		15.18%	0.00%	0.00%		0.00%
7	Deferred JDITC - Long Term Debt	56,978	930	57,908		0.20%	4.27%	0.01%		0.01%
8	Deferred JDITC - Preferred Stock	210	(29)	181		0.00%	4.50%	0.00%	1.3381	0.00%
9	Deferred JDITC - Common Equity	58,860	(949)	57,911		0.20%	10.25%	0.02%	1.3381	0.03%
10	Total	29,180,776	(293)	29,180,483		100.00%		6.17%		7.64%

Notes

Source of Company Brief position capital structure and cost rates: Exhibit No.: A-210 (MRB-19)

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-21585

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 December 3, 2024, 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.

Crystal L. Chacon

Crystal L. Chacon

Subscribed and sworn to before me this 3rd day of December, 2024.

Melissa K. Harris

Melissa K. Harris, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 06/11/2027
Acting in the County of Hillsdale

ATTACHMENT 1 TO CASE NO. U-21585

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ATTACHMENT 1 TO CASE NO. U-21585

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ATTACHMENT 1 TO CASE NO. U-21585

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